HOLY CROSS ENERGY

INTEGRATED RESOURCE PLAN

SUBMITTED TO WESTERN AREA POWER ADMINISTRATION TO MEET THE REQUIREMENTS OF THE 1992 ENERGY POLICY ACT

SEPTEMBER 2007

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2007 Holy Cross Energy IRP Table of Contents

Executive Summary

Holy Cross Energy (HCE) is a cooperative association organized and incorporated under the laws of the State of Colorado as Holy Cross Electric Association, Inc, with its principal place of business in Glenwood Springs, Colorado. HCE meets the needs of its customers with power purchased at wholesale prices, including a portion purchased under contract from the Western Area Power Administration (Western). Power is transmitted and distributed over facilities owned by HCE. HCE serves more than 53,000 member-owner meters, providing energy to farms, ranches and rural communities that provide people and resources for the tourist and outdoor recreation industries in central Colorado.

The economic base of the area is largely dependent upon the tourism industry. The location and climate lends itself to many types of year round outdoor recreation such as winter sports, hiking, rafting, biking, golfing, hunting, fishing and sightseeing. HCE serves several ski resorts including the world famous developments at Vail, Beaver Creek, Aspen and Snowmass. As the recreation industry continues to expand, so have the cities, towns, and rural areas in order to provide the necessary housing, goods and services needed by both the tourist and permanent resident. Due to the importance of the environment to the tourism industry in the area, HCE's customers are placing an increased importance on maintaining the environment while keeping costs for power at a reasonable level. As an electrical cooperative, HCE is affected by the Renewable Portfolio Standard (RPS) recently passed by the Colorado state legislature, requiring a minimum percentage of power sold to customers be from a renewable source.

Peak usage has historically occurred in January or December and generally coincides with cold temperatures and an increase in the number of tourists staying at the ski resorts across HCE's territory. On average, summer usage is 50-60% of the peak winter usage (refer to Exhibit A for details). The growth of peak demand has been slower than energy growth over the last several years, but it has continued. Reasons for these changes include working with the ski areas to reduce peak demand in the winter months and growth of summer recreation, which increases energy sales without affecting peak demand.

HCE is a Western customer, and is required to submit an Integrated Resource Plan (IRP) every five years under the Energy Policy Act of 1992. The IRP described herein was developed to evaluate reasonable alternatives available for meeting future power requirements. Options include purchasing power from various sources, adding new generating units, and demand-side management alternatives. The intent of this report is to outline HCE's IRP process and satisfy the requirements of Western.

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Resource Options

Supply Side

HCE currently purchases firm power for its customers primarily from Public Service Company of Colorado (PSCo) and Western. The key provisions of the Power Supply Agreement (PSA) with PSCo as they relate to HCE's resources and the IRP are:

- PSCo shall provide HCE's full demand and energy requirements in excess of the preference power from Western, purchases from Qualifying Facilities (QF) and economy purchases through April 15, 2022. PSCo has the right to terminate service on April 15, 2020 with five years prior notice.
- As of December 31, 2004, HCE has the option to switch to partial requirements service, with 12 months notice for each reduction of 20% of the maximum load shifted away from PSCo.
- HCE may purchase any amount of economy energy from any available source, up to PSCo's hourly sales to HCE. HCE remains liable for the demand charge payable to PSCo based on its total load, less the amount purchased from Western and any QFs.
- HCE may participate in PSCo generation capacity additions, with a maximum capacity participation in any single PSCo project limited to 30% of the projected HCE system peak demand.
- If a QF locates on the HCE system and contracts with HCE for the purchase of its output, HCE can reduce its purchase of demand and energy from PSCo, commensurate with the purchase from the QF.

The rates associated with firm purchased power from PSCo include both a demand charge and an energy charge. The demand charge is $10.12 per kW per month. There are no ratchet or minimum demand billing provisions in the rate. The energy rate for firm power from PSCo couples a base rate of $23.57 per MWh with a fuel cost adjustment. The demand charge and energy rates are constant and the fuel cost adjustments vary with PSCo's fuel costs for a given billing period. These charges exclude transmission services, but do include ancillary services. PSCo has the ability to file rate changes with the Federal Energy Regulatory Commission.

PSCo is regulated by the Colorado Public Utilities Commission (CPUC) and is thereby obligated to file a Least-Cost Resource Plan. The latest annual update to that plan is attached as Exhibit B. An annual update is due in October 2007 for submission to the CPUC and will be available online at the CPUC website (http://www.dora.state.co.us/puc). The portion of power that HCE purchases from PSCo has undergone a formal resource planning and approval process under the CPUC.

Since the last time HCE filed an IRP with Western, HCE has purchased eight percent of the output from a 750 MW coal-fired electric generation unit (Comanche 3) currently under construction as an addition to an existing PSCo power station. The facility is located in southern Colorado, near the city of Pueblo and completion is estimated in late 2009. It will be the cleanest coal unit in Colorado to date and will more than double the total output of the station. HCE's portion of the output from Comanche 3 is estimated to be approximately 60 MW. Purchases from PSCo will be reduced by a proportionate amount when the plant comes online. HCE went through a request for proposal process, conducted by outside consultants, to evaluate the merits of purchasing a portion of the Comanche 3 power station against other proposals. The results demonstrated that Comanche 3 may save HCE consumers as much as 250 million dollars over 30 years and were the least cost option.

HCE is continuing to purchase 5 MW of wind energy from PSCo under the PSA. HCE pays an additional $0.0242 per kWh over the current rate paid under the PSA for this power. HCE in turn sells this wind product to its customers at a premium of $2.50 per 100 kWh block above their tariffed rate. HCE has been very successful with this program; interest in purchasing renewable energy from customers has outstripped availability. There is a waiting list for participation in this program and HCE is exploring options to expand availability.

Due to the high customer demand for 'green' power, HCE has also instituted a local renewable energy pool that works in a similar manner to the wind program. HCE offers net metering for local renewable generation that is grid connected. This is part of the WE CARE (With Efficiency, Conservation And Renewable Energy) program, which includes measures to increase demand side efficiency and to encourage small scale renewable power generation in

HCE's service area. The net metering program has expanded rapidly since the last IRP. HCE now has 73 photovoltaic systems, one wind turbine, and three small hydro systems that are net metered. Additionally, Holy Cross has entered into agreements with 3 hydro-electric generators under the QF option of the PSCo contract. HCE anticipates that this growth will continue over the next several years and will promote the addition of more renewable distributed generation. Power from local renewables is marketed in 75 kWh blocks to interested customers. The premium prices paid to local renewable generators are funded by other customers who purchase these green products.

Interest in renewable generation has continued to grow according to the last two surveys conducted by HCE. Customers indicated their interest in funding 50 kW or larger renewable generation projects within HCE's service territory. Emphasis will be placed on such projects as HCE continues to evaluate supply options outside the full-requirements contract with PSCo. Due to uncertainty in the power and gas markets, proposed legislation at the federal and state levels that could impose emissions regulations, and increased consumer interest, HCE will aggressively pursue renewable generation.

HCE's current supply side demand and energy forecasts are depicted in the graphs in Exhibit C. The 'Additional Capacity' and 'Additional Energy' fields represent the additional capacity and energy that HCE would need to fill if the PSCo PSA lapses after 2020. HCE hopes to expand the portion of the power supply generated from renewable sources, but this expected growth is not depicted on the graphs.

Demand Side

HCE had Stone & Webster Management Consultants, Inc. prepare HCE's IRP in 1997. The demand side resources that were analyzed at that time failed at least one of the standard economic tests used for evaluating demand-side management resources and programs. It is HCE's opinion that the situation has not changed enough to alter the outcome of this analysis. A copy of this analysis is attached as Exhibit D. In 2006, HCE had a monthly load factor in the 75-85% range for 10 months of the year (refer to Exhibit A). The yearly load factor has improved since the 1997 IRP from 49.25% in 1995 to 55.89% in 2006 (refer to Exhibits D and

A, respectively). This makes demand-side management less cost effective than when the analysis was first completed. However, HCE has encouraged its members to implement efficiency and conservation measures.

Despite the lack of economic benefits, HCE's customers have expressed significant interest in improved energy efficiency and conservation. To that end, HCE's WE CARE program offers incentives to customers to improve efficiency and decrease consumption. The incentives include rebates and net-metering for grid-connected renewable energy generation, rebates for the purchase of select Energy Star® appliances and devices, and a rebate for disposal of old, inefficient refrigerators. In addition, HCE personnel are available to conduct residential and limited scope commercial energy audits on request. These limited scope audits are free of charge and include recommendations for efficiency and conservation measures. During residential audits, HCE personnel install several measures to reduce consumption (2 compact fluorescent light bulbs or one CFL and a water heater blanket) at no cost to the customer. In-depth commercial and industrial audits are available as part of a grant for evaluation or implementation of efficiency or conservation measures for qualifying customers. 228 residential audits and 37 commercial audits have been conducted between August 1, 2006 and July 31, 2007

HCE has worked with and created rates for Vail Resorts, Inc and the Aspen Skiing Company to encourage reduction of HCE's system peak. These rates have been successful in keeping their snowmaking facilities turned off during peak usage times in the winter. The savings resulting from the reduced demand are passed on to the customer. Similarly, a number of residential and commercial customers, represented by 104 additional meters, have agreed to use time-of-day rates that discourage on-peak usage.

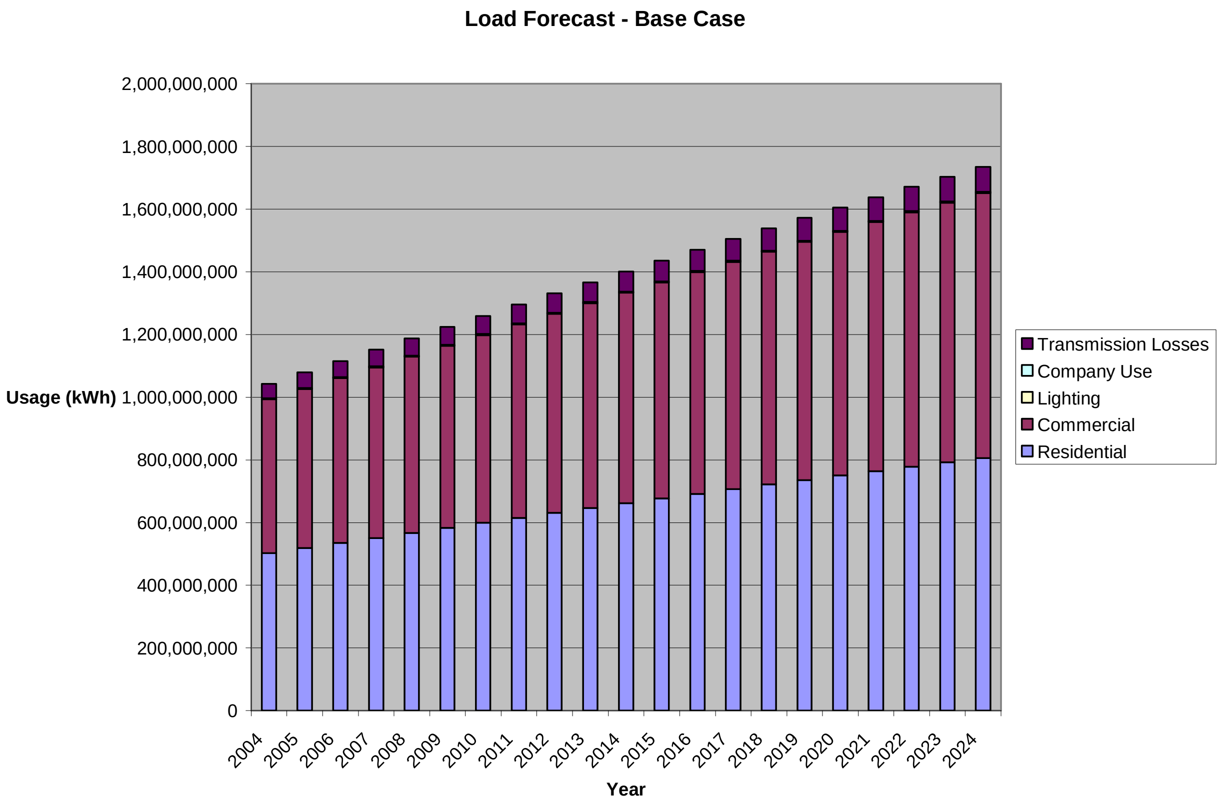
Environmental Issues

HCE does not currently operate any production facilities, but purchases the majority of its energy requirements from other utilities. A portion of these purchases are from Western and are hydro-based. The balance of energy purchases are from PSCo under the PSA or from other regional generating facilities until the Comanche 3 plant becomes operational. However, HCE recognizes the need for environmental responsibility and is making efforts to reduce its environmental impact. HCE has entered into a ten year agreement to purchase Renewable Energy Credits (RECs) from the Raft River Geothermal Power Plant from 2008 to 2017. The plant is expected to produce approximately 87,000 RECs each year, which will be used to offset the carbon dioxide produced by other sources from which HCE purchases power.

Colorado's legislature recently passed a Renewable Portfolio Standard (RPS) that affects HCE. It requires one percent of HCE's retail energy sales to be produced by means of renewable generation in 2008-2010. The percentage increases over time to 10% by 2020 and thereafter with an emphasis on distributed generation. The requirements through 2010 havebeen met and exceeded by HCE. Six percent of HCE's current power supply portfolio is generated from renewable sources. Internal goals set by HCE's Board of Directors exceed the Colorado RPS into the foreseeable future. HCE's current goals are to increase power supplied from renewable sources to 20% of total load by 2015 and to reduce the growth rate of carbon dioxide emissions from the generation of electricity used by their customers to one-half of the load growth rate.

Load Forecast

HCE staff performed load forecasting in 2004 for a 20 year period, beginning in 2005 and ending in 2024. Historical data was compiled from the Rural Utilities Service (RUS) that breaks down energy sales into major categories: residential use, commercial use, company use, street lighting, and transmission losses. From this data, forecasts for each category were made and summed to produce a total load forecast. Econometric information provided by Woods and Poole Economics, Inc, based in Washington, D.C., was used to estimate household, population, and employment growth by county. This data allowed HCE to estimate baseline, high and low forecasts for growth in each load class. The key load data from this forecast are attached as Exhibit E. The base-case supply side forecast is depicted in the graph below, shown by consumption class. Company use and street lighting represent less than one percent of total usage and are not visible on the graph.



Public Participation

HCE encourages public participation in planning and operations to the greatest practical extent. Two surveys have been conducted since the last IRP was filed to determine HCE's performance and customers' preferences. Based on these efforts, consumers' most significant concerns are reliability of electric service and interest in expanding HCE's portfolio of renewable energy. The latest survey, conducted in the summer of 2007, is attached as Exhibit F, along with a summary of the results. This survey showed an increase in environmental awareness and a willingness to support a rate increase for the financing of renewable generation facilities.

In addition to surveys, HCE allows for public participation by:

- Holding open board meetings and annual meetings.
- Holding director elections for every position on the board every three years.

- Supporting and working with two local community groups to encourage energy efficiency: Community Office for Resource Efficiency (CORE) and Eagle Valley Alliance for Sustainability (EVAS).
- Seeking feedback via a tri-annual member newsletter.
- Holding periodic meetings with members and governmental entities on specific issues.
- Supporting an open door policy for consumers (i.e. posting staff names and contact information for specific information).

Action Plan

Supply Side

As discussed earlier, HCE has the ability to begin reducing the portion of power purchased from PSCo under the PSA. At this time, HCE has not opted to reduce the load from PSCo, but continues to evaluate alternatives to the PSA as appropriate. Other alternatives include options for restructuring the PSA contract to aid in acquiring additional renewable resources. HCE will continue to seek supply side options that meet the requirements of high reliability and reasonable pricing, with an emphasis on environmental responsibility. HCE will continue to promote the wind program and local renewable programs to be sold in the renewable resource pool. HCE will seek to create partnerships with interested members to further expand consumer-owned renewable generation in its service area.

HCE will track growth in generation from the new renewable resources that are developed in its system and will seek to purchase power from more renewable and low-emission facilities when possible. The results of these efforts will be documented in a yearly Carbon Report Card produced by HCE staff.

Demand Side

HCE will aggressively examine all options to promote energy conservation through expanded incentives and education. HCE will also continue to provide energy conservation, efficiency and load management information to customers through the member newsletter and company website. The energy audit program will continue with the goal of expanding the number of members using the service. HCE will continue to promote and incent the net metering program for small grid connected renewable generation systems and design rates that encourage peak demand reduction. Evaluation of peak shaving measures and consumer owned backup generation facilities are being conducted when practicable. Efforts to educate consumers will continue through information posted on the website, work with local community groups and support of an energy efficiency education program for local fifth graders. HCE continues to evaluate and reduce transformer losses whenever appropriate.

Calculations of demand savings achieved by rate design are the primary measurement tool for the demand-side measures taken by HCE, where reasonable.

Exhibit A

Holy Cross Energy Usage & Demand Profile, 2006

Month	Usage (kWh)	Maximum Demand	Load Factor
Jan	125,452,063	203,562	82.83%
Feb	110,367,538	201,085	81.68%
Mar	111,753,885	199,259	75.38%
Apr	81,749,203	155,359	73.08%
May	71,140,263	112,669	84.87%
Jun	72,257,380	125,069	80.24%
Jul	79,639,149	129,809	82.46%
Aug	76,951,118	126,508	81.76%
Sep	73,531,047	132,753	76.93%
Oct	84,664,435	151,677	75.03%
Nov	106,825,106	200,850	73.87%
Dec	141,617,937	225,999	84.22%

Holy Cross Energy Sales, 5 Year History

Year	Sales (kWh)	Revenue	Annual Load Factor
2002	954,156,621	$61,012,712	55.15%
2003	958,533,756	$62,263,488	52.29%
2004	994,693,582	$68,470,422	52.30%
2005	1,030,247,451	$81,862,114	56.48%
2006	1,081,922,443	$88,529,514	55.89%

Exhibit B

October 2006 PSCO LCP Update

Public Service Company of Colorado

Annual Progress Report
2003 Public Service LCP

October 2006

1. Introduction

On April 30, 2004 Public Service filed its 2003 Least-Cost Resource Plan (Docket No. 04A-214E). This annual progress report provides the Commission with an update on Public Service's resource planning and acquisition efforts since the Company's last annual progress report, which was filed on December 28, 2005. The report is in compliance with the Colorado Public Utilities Commission (CPUC) Electric Least-Cost Resource Planning (LCP) Rule 3614(a), which states that the utility shall file annual progress reports that are intended to "inform the Commission of the utility's efforts under the approved plan."

Per LCP Rule 3614(a), this report contains:

- An updated annual electric demand and energy forecast
- An updated evaluation of existing generation, transmission and DSM resources
- An updated assessment of need for additional resources
- An updated report on the utility's resource acquisition plan
- An update on the status of several studies mandated by the Comprehensive LCP Settlement Agreement filed on December 3, 2004

As highlighted below, several major resource planning and acquisition efforts have transpired since the last progress report was filed.

- Construction continues on the 750 MW Comanche 3 coal-fired generation unit. The Company expects to meet budget and timeline goals for this project.

- The All–Source RFP Bid Evaluation process for years 2007-2012 is complete. As a result of this process, the Company has executed power purchase contracts for all three wind facilities selected, totaling approximately 775 MWs and the five gas-fired facilities selected, totaling approximately 1,300 MW. Therefore, Public Service has completed contracts for resource additions to meet our customers forecasted electric demand through 2012.

- Public Service is continuing the evaluation and negotiation of the bids offered for 2013 as ordered by the Commission in Docket No. 05A-543E.

2. Updated Electric Sales and Demand Forecast

2.1 Forecast Overview

Public Service's firm electric sales are forecasted to increase at an average annual rate of 0.2% through 2010. This compares to historical growth since 2000 averaging 3.8% annually. Total firm peak demand increased 5.0% per year on average during the same period, in part due to increased wholesale sales, and is expected to decline by an average of 0.1% per year through 2010. This slightly declining growth rate in both the sales and demand forecasts, is driven by reductions in firm resale sales.

2.2 Forecast Methodology

The forecast methodology used by Public Service is fully described in the Company's 2003 LCP, filed with the Commission on April 30, 2004. The following discussion highlights differences between the methodology described in that filing and that used to develop the forecast reported in this update.

The forecast models used to develop the forecast presented in the 2003 LCP included historical data through December 2002. The current forecast is based on historical sales data through January 2006 and historical peak demand data through December 2005. Other updated data include a new economic forecast developed in February 2006, and estimates of expected reductions from Demand Side Management (DSM) programs developed in February 2006.

2.3 Forecast Models

All forecast models are specified as they were in the 2003 LCP with the following exceptions:

1) In the development of the commercial and industrial utilization variables (COOLUSE, HEATUSE, BASEUSE) Colorado Gross State Product was replaced with United States Gross Domestic Product (US_GDP).
2) Residential Electric Sales per Customer – The monthly binary variable for January was not significant, so was dropped. Monthly binary variables for October and November were added. Binary variables for April 2004 and July 2005 and a variable for monthly billing cycle days were added.
3) Commercial/Industrial Electric Sales – A variable for monthly billing cycle days was added. Binary variables for July 2004, August 2004, October 2004, December 2004, February 2005, and the timing of CRS implementation were added. The period included in the regression was changed to begin in January 1993.
4) Electric Street and Highway Lighting Sales – The variable for monthly hours of daylight and the monthly binary variable for July were not significant, so they were dropped. A monthly binary for November was added. The ARMA model applied to the model errors was changed from an ARMA (1,0) to an ARMA (2,0).
5) Other Public Authority – Rather than a single model for Other Public Authority, there is now a separate model for each of the two customers that remain in this category. They are very similar to the class level model, using the Commercial/Industrial Base

and Cooling variables and monthly binary variables. The forecast for RTD has been modified to include expected increases from expansion of the light rail system.

6) Residential Contribution to System Peak Demand – The variable "Custs_Over90" (residential customers * annual year-to-date total number of days with a maximum temperature over 90 Degree) was not significant in the model, so was dropped. Real Personal Income (RealPersInc) was added as a variable. A monthly binary variable for December was added, as were binary variables for August 2002, October 2005, and a variable for the timing of CRS. The period included in the regression was changed to begin in January 1994, which resulted in the removal of 2 additional binary variables – April 1992 and October 1993.
7) Non-Residential Contribution to System Peak Demand – The binary variable for August 2002 was not significant, so it was removed. Binary variables were added for June 2004, October 2004 and October 2005.

Forecasts for large industrial customers and for wholesale customers were prepared as described in the 2003 LCP.

2.4 Energy Sales Forecast

Residential sales have increased an average of 2.4% per year over the past five years. Customer growth is expected to return to levels seen before 2004. There has been a decline in weather normalized use per customer in the past two years. Use per customer is expected to decline in the current year, then return to slow growth over the next four years. As a result, residential sales are forecast to increase 2.1% per year on average compared to the 2.3% growth of the previous forecast, developed in December 2005.

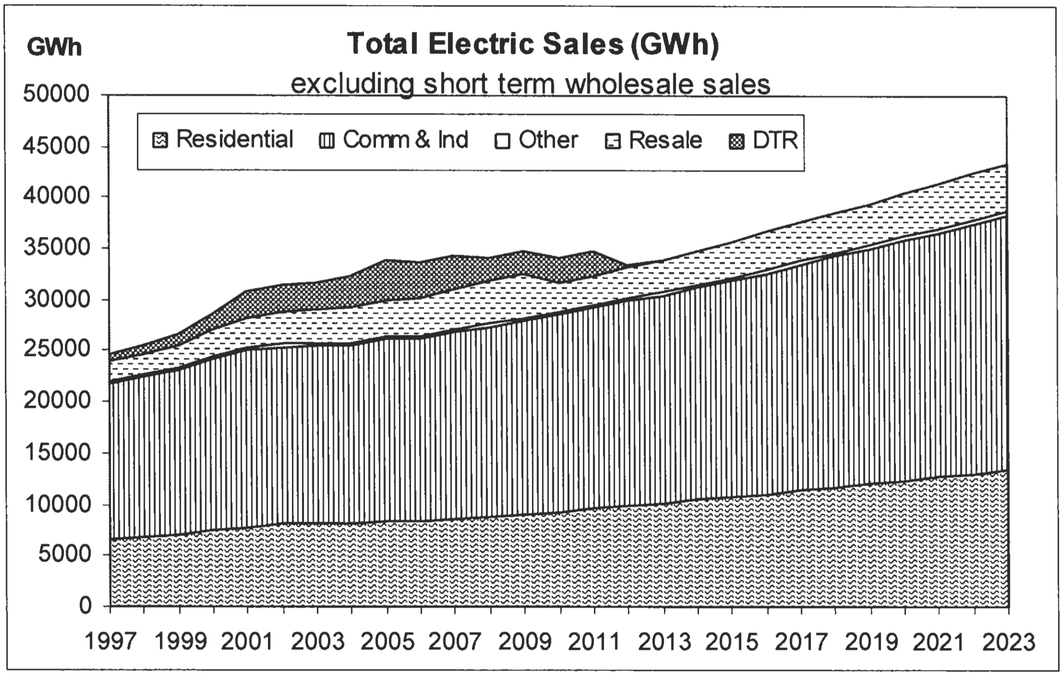
Commercial and industrial sales are projected to increase at an average annual rate of 1.7% over the next five years, following average growth of 1.1% per year during the past five years. Economic growth, which has been very slow since 2001, but is improving and is expected to strengthen by 2007, results in a slightly higher growth rate than the 1.5% predicted in the December 2005 forecast.

During the past five years total retail sales have increased 1.5%. Increased commercial and industrial sales growth will result in higher growth of 1.8% through 2010.

Total long term firm resale sales increased by 13.0% over the past five years, primarily due to the addition of three customers - Cheyenne Light, Fuel and Power Company (CLF&P), the Municipal Energy Agency of Nebraska (MEAN), and the Western Area Power Administration (WAPA). Over the period from 2005 through 2010 sales are expected to decrease by –7.2% per year. This is lower growth than the -0.4% expected in the December 2005 forecast. The decrease from current levels is due to the expiration of current contracts with the same three customers listed above and due to participation of some resale customers in Comanche 3, which is scheduled to start up in 2010.

Public Service's total firm (retail plus long-term firm resale) electric sales are projected to grow at 0.2% per year on average for the next five years. Growth during the past five years averaged 3.8% annually. The lower projected growth rate is due to the expiration of firm wholesale contracts and the participation of some resale customers in Comanche 3.

Figure 2.4.1 Annual and Forecasted Electric Sales (GWH)



Note: The "Other" category is imperceptible on this graph.
DTR: Defined Term Resale – contracts expire during the forecast period.

Table 2.4.1 Actual and Forecasted Electric Sales (GWH)

Year	2005 LCP Update Sales Forecast	2006 LCP Update Sales Forecast	Difference
1999	26,579	26,579	0
2000	28,714	28,714	0
2001	30,810	30,810	0
2002	31,432	31,432	0
2003	31,718	31,718	0
2004	32,275	32,275	0
2005	33,921	33,921	0
2006	33,777	33,782	5
2007	34,155	34,312	157
2008	33,858	34,087	229
2009	34,494	34,844	350
2010	33,894	34,048	154
2011	34,429	34,814	385
2012	33,047	33,389	342
2013	33,488	33,911	423

Note: Values above the heavy line are actual historical values; values below the line are forecasts.

2.5 Demand Forecast

Firm residential coincident summer peak demand increased an average of 5.2% per year from 2001 to 2006. Growth over the next five years through 2011 is expected to average approximately 3.5%. This is higher than the 2.8% expected growth in the December 2005 forecast.

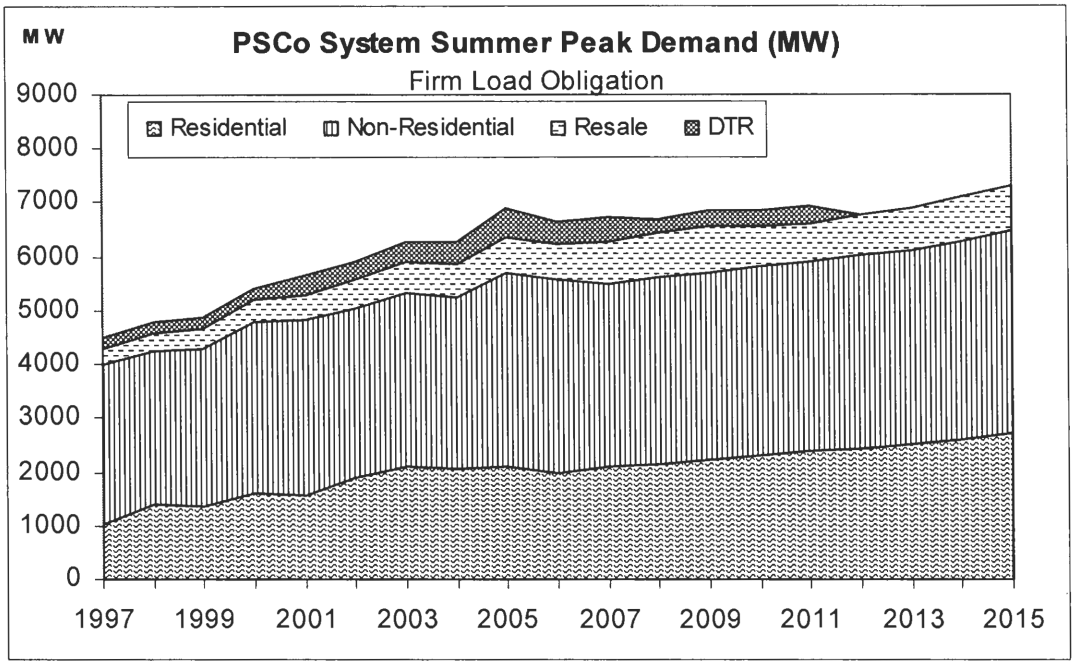
Firm commercial and industrial peak demand is projected to decrease over the next five years at approximately -0.3% per year on average, slightly lower than the 0.8% growth over five years in the December 2005 forecast. Firm commercial and industrial peak demand growth from 2001 to 2006 was 1.7%.

Since 2001 total firm retail demand has increased an average of 2.8% per year. Slower growth, especially in the commercial and industrial class, combined with larger DSM reductions than seen historically, will result in reduced growth of 1.2% through 2011.

Total long term firm resale demand grew by an average of 5.8% per year from 2001 through 2006, and is expected to decline at the average rate of –1.4% per year through 2011 due to the termination of contracts with WAPA in 2006, MEAN in 2007, and CLF&P at the end of 2007 and the participation of some Public Service resale customers in Comanche 3.

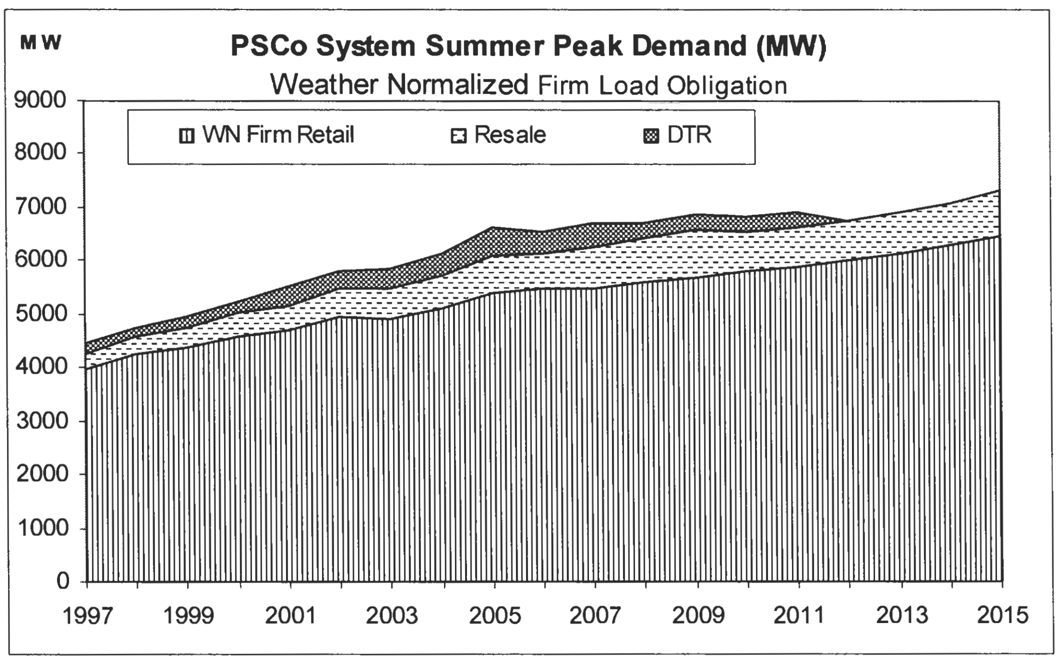
Since 2001, Public Service's total firm peak demand has increased an average of 3.3% per year (3.4% weather-adjusted). In July 2006 a firm peak demand of 6,656 MW was reached. This was a decrease of 241 MW from the 2005 peak. On a weather-adjusted basis, the July 2006 total firm peak demand of 6,543 MW was a decrease of 73 MW (1.1%) from the 2005 weather-adjusted peak of 6,616 MW. An increase of 72 MW (1.1%) from the actual 2006 peak is expected for 2007. On a weather-adjusted basis, the increase for 2007 is 185 MW (2.8%). Growth over the next five years will be slower than in the past 5 years due to slower retail peak demand growth and reduction of contracted firm wholesale load. Overall, the average growth rate through 2011 is projected to be 1.1% from the weather adjusted 2006 peak. This is slightly higher than the 0.7% growth expected in the December 2005 forecast.

Figure 2.5.1 Actual and Forecasted Summer Peak Demand (MW)



DTR: Defined Term Resale – contracts expire during the forecast period.

Figure 2.5.2 Actual and Forecasted Summer Peak Demand (MW) Weather Normalized Actuals



DTR: Defined Term Resale – contracts expire during the forecast period.

Table 2.5.1 Actual and Forecasted Summer Peak Demand (MW)

Year	2005 LCP Update Forecast Firm Load	2006 LCP Update Forecast Firm Load	Difference
1998	4,771	4,771	0
1999	4,858	4,858	0
2000	5,416	5,416	0
2001	5,655	5,655	0
2002	5,895	5,895	0
2003	6,268	6,268	0
2004	6,274	6,274	0
2005	6,897	6,897	0
2006	6,556	6,656	100
2007	6,769	6,728	-41
2008	6,768	6,698	-70
2009	6,939	6,858	-81
2010	6,845	6,852	7
2011	7,000	6,918	-82
2012	6,836	6,757	-79
2013	6,981	6,896	-85

Note: Values above the heavy line are actual historical values; values below the line are forecasts.

3. Update on Existing Generation, Transmission, New Generation Development and Demand-Side Resources

3.1 Existing Generation Resources

Public Service's power supply portfolio consists of both Company-owned plants and purchased power capacity and energy. In 2007, these sources will provide over 7,800 MW of net dependable capacity.

Table 3.1.1 shows the major components of Public Service's net dependable capacity (NDC) for years 2007 through 2013. The capacities shown include the addition of 500 MW from Public Service's share of the Comanche 3 unit and the bids that have been selected through the 2005 All-Source RFP through 2012. The status of Comanche 3 and the All-Source RFP are described in more detail under Sections 3.3 and 3.4 of this report.

Table 3.1.1 Public Service Net Dependable Capacity, 2007 – 2013

	2007	2008	2009	2010	2011	2012	2013
Installed Net Capacity	3,838	3,838	3,838	4,338	4,338	4,338	4,338
Total Firm Purchases	3,707	3,732	3,975	3,881	3,837	3,522	2,685
Short-Term Purchases	158	99	41	-	-	-	-
SPS Diversity Exchange	101	101	101	101	101	101	101
Total Net Capacity	7,804	7,770	7,955	8,320	8,276	7,961	7,124

3.2 Electric Transmission Projects

This section describes the status of major transmission projects that are either underway or were completed since the last annual progress report.

- **Chambers 230/115kv Transmission Inter tie Project**
  This project consists of the construction of approximately 4 miles of new 230kV double circuit transmission, a new substation, referred to as the Chambers Substation that will contain one 230/115kV autotransformer, and 1 mile of new 115kV transmission. The Project will link the outer 230kV transmission belt to the 115kV transmission network in the northeast metro vicinity. A CPCN from the Colorado PUC was granted in fall of 2003. The project initially had an in-service date of May 2005 but it has been delayed due to land rights issues. The current in service date is May 2008.

- **Sandown – Leetsdale 115kV Line**
  The project consists of a new five and one-half mile 230kV capable single circuit transmission line, which will provide relief to the heavily loaded Denver-metro underground transmission system by creating a new path from the Cherokee power plant to the Leetsdale Substation. The transmission line will initially operate at 115 kV. It is anticipated that most of the new line will be constructed underground due

to technical issues associated with existing land use and residential density in the area. Public Service has filed for a CPCN for this project with the CPUC and it is anticipated that the CPCN will be granted by end of January 2007. This project is planned to be in service by May of 2009.

- **Denver Terminal – Dakota – Arapahoe 230kV Transmission Project**
  The project consists of a new 230kV overhead transmission line between the Denver Terminal, Dakota, and Arapahoe Substations. The project was granted a CPCN by the Colorado Public Utilities Commission in August 2003, and had a planned in-service date of May 2005. However, due to delays in permitting, and securing private and city easements the in-service date has been delayed to May 2007.

- **Comanche to Daniel Park 345kV Transmission Project**
  The Comanche to Daniels Park 345kV Transmission Project is planned to accommodate the CPUC approved 750 MW Comanche Unit #3 Generation Project. The project consists of approximately 125 miles of double circuit 345kV transmission between the Comanche Station and the Daniels Park substation. This will consist of approximately 50 miles of new transmission and 75 miles of re-build to existing transmission, and 345/230kV autotransformers at both Comanche and Daniels Park substations. This project received the CPCN from the Colorado PUC in September 2006. Construction is expected to begin in the summer of 2007 and the Project is planned to be in-service by May 2009.

3.3 New Generation Supplies and DSM

This section describes the status of projects selected to meet resource needs including Public Service owned generation and new generation agreements.

- **Comanche 3**
  Construction began on the 750 MW Comanche 3 coal-fired generation unit in December 2005. The project consists of locating a third electric generating unit at Comanche Station. The third unit will consist of a 750 MW supercritical coal fired facility. Public Service will be the operator of the facility. Public Service plans to own 500 MW of the facility with Intermountain Electric Association and Holy Cross Electric participating in the remaining 250 MW. Commercial Operation is expected in the Fall of 2009. The Project is proceeding within budget and is on schedule.

- **PacifiCorp Settlement**
  Public Service and PacifiCorp are parties to a Long-term Power Sales Agreement ("LTPSA") for 176 MW of capacity and energy. In 2002, Public Service exercised its early termination right under the contract which initiated a ramping down of the capacity and energy purchased starting in 2008 and ending in 2012. PacifiCorp disputed the early termination notice. Public Service and PacifiCorp reached agreement on terms and conditions for a new energy exchange agreement that resolved certain of the parties' outstanding issues. Public Service filed for approval of this agreement with the Commission in Docket 06A-015E. In September 2006, the Administrative Law Judge presiding over this docket recommended to the Commission that the agreement be approved. The Commission has not yet ruled on this recommendation.

- **Renewable RFP**
  The Commission was informed of the results of the Renewable RFP in the March 2005 in accordance with LCP Rule 3614(b)(iii). Power purchase agreements have been signed for the 60 MW of Spring Canyon facility as well as the two small hydro facilities (approx. 4 MW in aggregate) selected in this RFP.

- **All-Source RFP**
  Contracts for all but two supply-side bids selected in the All-Source solicitation have been signed. Table 3.3.1 below summarizes the final bid selections through 2012. The Company continues to evaluate bids for 2013.

Table 3.3.1 Added Supply-Side Capacity from All-Source RFP through 2012

Bid No.	Location	MW	COD	Technology
G029	Frederick, CO	269	2007	Gas CT
G005	Brush, CO	75	2007	Gas CT
G003	Jefferson County, CO	115/228	2008/2012	Recip Engines
G031	El Paso County, CO	500	2009	Gas CC
G016	Morgan County, CO	253	2012	Gas CT
W009	Logan County, CO	400	2006	Wind
W014	Prowers County, CO	75	2006	Wind
W022	Weld County, CO	300	2006	Wind
B003	Arapahoe County	3.2	2007	Landfill Gas
O003	Clear Creek	0.22	2007	Hydro

The initial supply-side bid selections were described in the December 2005 Bid Evaluation Report submitted to the Commission in accordance with LCP Rule 3614(b)(iii). Since that report, one gas-fired peaking bid (G025) was removed from further consideration and replaced with a backup bid (G003). Contracts for the 3.2 MW landfill gas and 0.220 MW hydro facilities are still being negotiated. Power purchase contracts have been executed for all other selected supply-side bids.

Table 3.3.2 DSM bids selected from the All-Source RFP

Bid No.	Location	MW	COD	Technology
D003	PSCo System	4.2	2007	DSM Custom
D006	PSCo System	15	2007	DSM Direct Lighting Controls
D009	PSCo System	7.5	2007	DSM lighting

The three DSM bids selected from the All-Source RFP are identified in Table 3.3.2. Bid D006 withdrew from negotiations and is no longer being considered. Public Service continues to negotiate with the remaining two bidders.

- **Docket 05A-543E - Public Service application to shorten the 2003 LCP resource acquisition period**

  On December 28, 2005, Public Service filed an application seeking to amend its approved 2003 Least-Cost Resource Plan by changing the resource acquisition period from a ten year period (2003 through 2013) to a nine year period (2003 through 2012). The Company believed that shortening the resource acquisition period and subsequently not filling the 2013 resource need from the pool of bids received in response to the 2005 All-Source RFP was in the best interest of ratepayers.

  In the months following the December 28, 2005 application, Public Service performed additional analyses of the expected benefits to ratepayers of shortening the resource acquisition period. When these analyses showed less ratepayer benefits than originally estimated, Public Service filed a motion to withdraw its application on June 2, 2006. On June 7 2006, the Commission granted Public Service's motion[1] and ordered the Company to begin its delayed evaluation of 2013 bids as soon as possible and to complete the process by December 15, 2006 for 2013 resources that require new construction. Public Service is performing evaluations and negotiations of the 2013 bids as ordered by the Commission.

3.4 Company Sponsored Demand-side Programs

In January 2006, Public Service began to roll out its expanded portfolio of DSM programs intended to help the Company meet its 2006-2013 goals of 320 MW and 800 GWh. This portfolio includes business programs for building efficiency, compressed air, cooling, lighting, motors, new construction, and custom projects, as well as residential programs for evaporative cooling, lighting, and Saver's Switch. Public Service plans to launch refrigerator recycling and air conditioner tune-ups by Spring 2007. The Company will report its first-year achievements with these programs in its 2006 DSMCA filing on April 1, 2007.

1 See Decision No. C06-0730

4. Resource Needs Assessment

Table 4.1 shows the current loads and resources (L&R) balance for the Public Service system for years 2007 through 2013. The loads shown in the table reflect the 2006 LCP Update forecast of peak demand described in Section 2. The resources shown on the table include all current purchased power contracts, as well as Public Service-owned resources, including the Company's 500 MW share of the Comanche 3 unit starting in 2010. The table also includes new resources that the Company is pursuing as a result of the 2005 All-Source RFP through 2012. The Company continues to evaluate bids for 2013 COD and has not included any of these in the table.

Table 4.1

PSCo Loads & Resources Balance Summer 2007-2013 Based on 2006 LCP Update Forecast	2007	2008	2009	2010	2011	2012	2013
Existing PSCo Capacity							
Installed Net Dependable Capacity	*3838*	*3838*	*3838*	*3838*	*3838*	*3838*	*3838*
PSCo Share of Comanche 3				500	500	500	500
Firm Purchased Capacity							
Utility Purchases							
Basin Electric Power Cooperative No.1	100	100	100	100	100	100	100
Basin Electric Power Cooperative No.2	75	75	75	75	75	75	75
Tri-State G&T No.2	100	100	100	100	100	100	100
Tri-State G&T No.3	25	25	25	25	25	25	25
Tri-State G&T No.5	100	100	100	100	100	0	0
Platte River Power Authority	30	0	0	0	0	0	0
Pacificorp LTPSA	176	141	107	71	36	0	0
Pacificorp Exchange Agreement	0	25	50	100	125	150	150
Wheeling Losses	(9)	(9)	(9)	(9)	(9)	(9)	(9)
Subtotal	**597**	**557**	**548**	**562**	**552**	**441**	**441**
IPP / EWG Purchases							
ManChief Power Company	263	263	263	263	263	0	0
Black Hills Valmont 7 & 8	81	81	81	81	81	81	0
Black Hills Arapahoe 5, 6, 7	122	122	122	122	122	122	0
Fountain Valley Midway	236	236	236	236	236	236	0
Brush 4D	130	130	130	130	130	0	0
Tri-State Limon	63	63	63	63	63	0	0
Tri-State Brighton	128	128	128	128	128	128	0
Calpine Blue Spruce	270	270	270	270	270	270	0
Front Range Power	161	133	103	0	0	0	0
PG&E Plains End	113	113	113	113	113	0	0
Black Hills Gillette	40	0	0	0	0	0	0
Black Hills WyGen	60	0	0	0	0	0	0
Western Colorado Power Co. - Ouray Phase 2	0	0	0	0	0	0	0
Thermo Fort Lupton	279	279	129	129	129	129	129
Calpine Rocky Mountain Energy Center	601	601	601	601	601	601	601
Colorado Green Wind	16	16	16	16	16	16	16
enXco Ridge Crest Wind	3	3	3	3	3	3	3
Invenergy Spring Canyon Wind	6	6	6	6	6	6	6
Subtotal	**2572**	**2444**	**2264**	**2161**	**2161**	**1592**	**755**
Qualifying Facilities (QF)							
Brush Cogen Partners (Brush 2)	68	68	0	0	0	0	0
Thermo Greeley (Monfort)	32	32	32	32	0	0	0
Thermo Power (UNC)	69	69	69	69	69	69	69
Small QFs	22	22	22	17	14	14	14
Subtotal	**191**	**191**	**123**	**118**	**83**	**83**	**83**
2005 All-Source Supply-Side Bids							
Invenergy Wind (10% capacity credit)	0	40	40	40	40	40	40
Greenlight Wind (10% capacity credit)	0	30	30	30	30	30	30
PPM Wind (10% capacity credit)	0	8	8	8	8	8	8
Invenergy Spindle CT	269	269	269	269	269	269	269
Gas Bid G005	75	75	75	75	75	75	75
Gas Bid G003	0	115	115	115	115	228	228
Gas Bid G031	0	0	500	500	500	500	500
Gas Bid G016	0	0	0	0	0	253	253
Landfill Bid B003	3.2	3.2	3.2	3.2	3.2	3.2	3.2
Hydro Bid O003	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Subtotal	**347**	**540**	**1,040**	**1,040**	**1,040**	**1,406**	**1,406**
Total Firm Purchases	**3,707**	**3,732**	**3,975**	**3,881**	**3,837**	**3,522**	**2,685**
Short-Term Seasonal Purchase Need	158	99	41	0	0	0	0
SPS Diversity Exchange	101	101	101	101	101	101	101
PSCo Net Dependable Capacity	***7804***	***7770***	***7955***	***8320***	***8276***	***7961***	***7124***
PSCo Native Load							
2006 LCP Update Forecast	**6,917**	**6,904**	**7,079**	**7,089**	**7,168**	**7,018**	**7,167**
Interruptible Load	96	98	99	101	103	104	106
Saver's Switch	93	108	122	136	147	157	165
PSCo Firm Load Obligation	***6728***	***6698***	***6858***	***6852***	***6918***	***6757***	***6896***
Reserve Margin %	16.0%	16.0%	16.0%	16.0%	16.0%	16.0%	16.0%
Reserve Requirement (MW)	1076	1072	1097	1096	1107	1081	1103
IREA & HCEA Backup	0	0	0	40	40	40	40
Actual Reserve Capacity	**1,076**	**1,072**	**1,097**	**1,468**	**1,358**	**1,204**	**228**
Resource Need (MW)	***0***	***0***	***0***	***(332)***	***(211)***	***(83)***	***916***

5. Additional Resource Planning Studies

In the Comprehensive Settlement Agreement in Dockets 04A-214E, 215E, and 216E, Public Service agreed to perform additional planning studies associated with various resource planning related topics. The following discussion provides a brief update of the status of these studies.

Wind Integration Study

For this study Public Service committed to examine the integration costs (a.k.a. ancillary costs) associated with adding various levels of wind to its system. Specifically, the Company agreed to examine the integration costs associated with wind penetration levels of 10%, 15%, and 20%, and use the results of the 15% level in evaluating wind bids received in response to the 2005 All-Source RFP. The Company completed its analysis of integration costs for 10% and 15% penetration levels in June 2005 and used the results of the 15% level in evaluating wind bids as promised. The analysis of integration costs for the 20% penetration level is in the final stages of analysis and review and is expected to be made available before the end of 2006.

Effective Load Carrying Capability (ELCC) of Wind Study

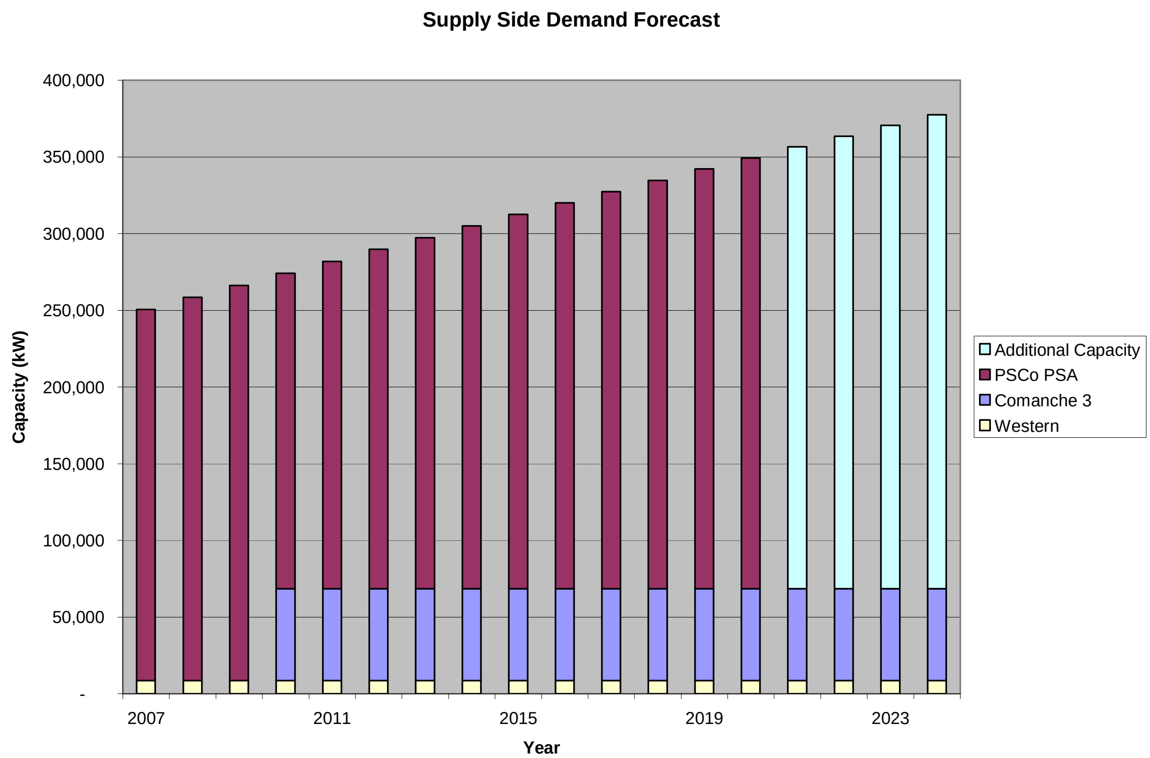
For this study Public Service committed to analyze the "capacity" value that wind generation resources provide to its system using a probabilistic methodology referred to as Effective Load Carrying Capability or ELCC. The Company agreed to file a report with the Commission detailing the study results by November 1, 2006. In June 2006, Public Service formed a Technical Review Committee (TRC) comprised of members from the Commission staff, Public Service personnel, and several industry experts. The purpose of the TRC is to incorporate the specific interest and knowledge of various industry individuals and experts into the study.

Public Service has completed the analyses needed for this study and is on schedule to file the study results with the Commission on November 1, 2006. However, the study will be filed in draft form to allow for review by the TRC. The final study will be filed no later than February 1, 2007.

Reserve Margin Study

Public Service committed to work jointly with Staff and OCC to work on developing a study scope and methodology for performing a probabilistic assessment of the appropriate planning reserve margin for the Public Service system. The study will consider the addition of the Comanche 3 unit as well as resources acquired in both the 2004 Renewable Energy RFP and 2005 All-Source RFP as well as weather related load variability; and the availability (both planned and unplanned) of both generation and transmission facilities. The results of this analysis are intended to inform the level of planning reserves that parties will recommend in Public Service's next resource plan which the Company plans to file in October 2007. The Company plans to initiate this reserve margin study in early 2007.

Exhibit C


Supply Side Demand Forecast
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
-
Capacity (kW)
2007
2011
2015
2019
2023
Year
Additional Capacity
PSCo PSA
Comanche 3
Western

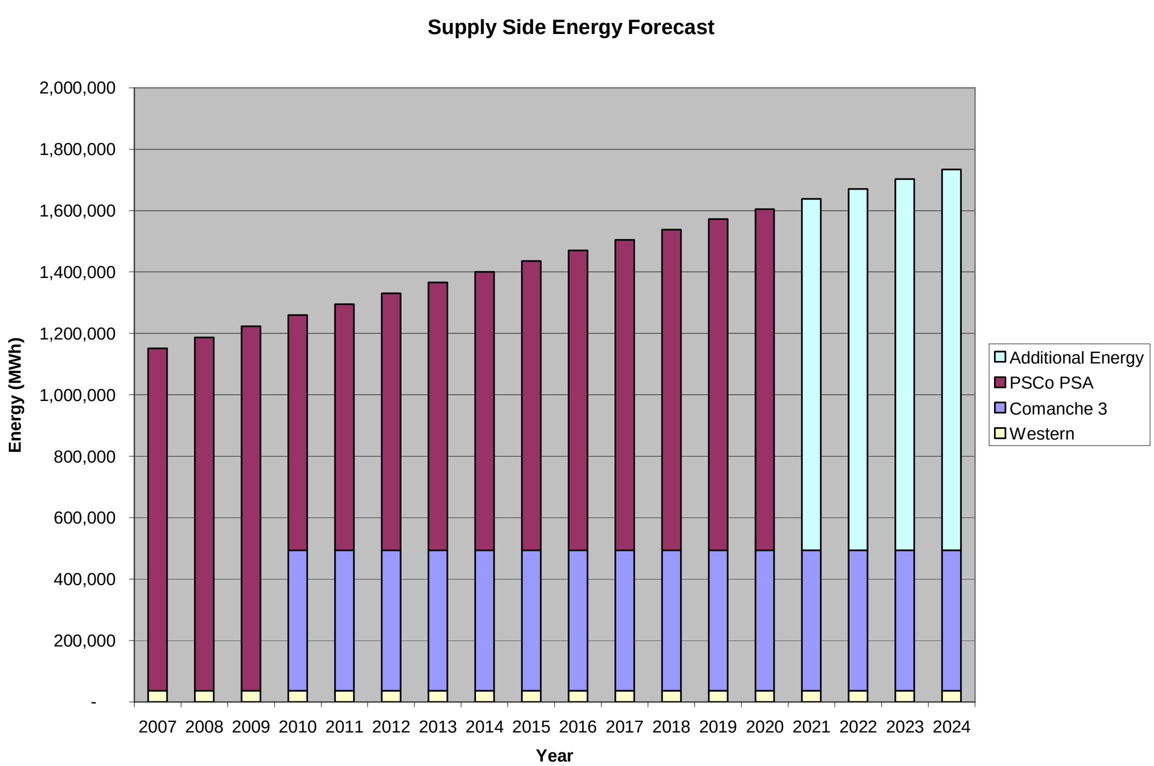

Supply Side Energy Forecast
2,000,000
1,800,000
1,600,000
1,400,000
1,200,000
1,000,000
800,000
600,000
400,000
200,000
-
Energy (MWh)
2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024
Year
Additional Energy
PSCo PSA
Comanche 3
Western

Exhibit D

1997 HCE IRP – Demand Side Analysis

INTEGRATED RESOURCE PLAN FOR
HOLY CROSS ELECTRIC ASSOCIATION

Overview

Holy Cross Electric Association (HCEA) currently purchases a portion of its energy requirements under a contract with the Western Area Power Administration (Western). Part of the requirements for extending the contract include the preparation and filing of an integrated resource plan, as specified in Part 905 of the Code of Federal Regulations (CFR). The integrated resource plan described herein was developed to evaluate reasonable alternatives available to meeting future power requirements. These options include purchased power from various sources, new generating units, and demand-side management (DSM) alternatives. The intent of this study is to help HCEA meets its goals and satisfy the requirements of Western.

HCEA Situation

Prior to its breakup as a result of a bankruptcy filing, Colorado-Ute Electric Association, Inc. supplied the bulk of the power requirements of HCEA, with the balance provided by Western. In conjunction with its acquisition of some of Colorado-Ute's production facilities, Public Service Company of Colorado (PSCO) replaced Colorado-Ute as the principal power supplier for HCEA. The power supply contract with PSCO was signed in February 1992 and provides that, for the initial 15-year period, PSCO will essentially provide for the full requirements of HCEA, excluding the power available from Western. After the initial 15-year period, HCEA will have the ability to reduce the purchases from PSCO and to develop and utilize other power resources that may be to its advantage. Therefore, prior to February 2007, the power requirements of HCEA and its customers in excess of the Western allotment (and excluding economy power purchases) are expected to be provided under the power supply agreement with PSCO.

HCEA recognizes the strategic planning nature of the IRP, based on the long-term commitments that may be made as a result of it. The electric utility industry is in a period of great transition, moving from a heavily regulated environment to a more competitive one. In the future, as access to the transmission system is opened, HCEA will likely find that both it and its customers will have a larger range of options for power. At the same time, HCEA's location may limit the availability of the sheer number of options compared to other areas.

Study Methodology

opportunities, challenges good & bad

The study methodology used develops an integrated resource plan (IRP) that incorporates the risks for HCEA and provides a schedule to implement the plan. The methodology strives to produce a flexible IRP that can be monitored to identify changes from the expected assumptions made in the study and the results anticipated from those changed assumptions.

The study methodology consisted of the following steps:

- define the IRP objectives for HCEA, consistent with Western objectives,
- define integrated resource plan alternatives,
- establish a load forecast for HCEA,
- screen the supply-side alternatives,
- complete a demand-side management screening analysis,
- integrate the DSM and supply-side alternatives, and
- develop short-term and long-term implementation plans.

The following sections of this report discuss the methodology, basic assumptions, areas investigated, and overall study results.

Objectives

Objectives of a plan must be clearly delineated because of the many factors influencing the planning process. Equally important, the objectives must be specified in ways that can be converted into an operational framework.

The objectives of this study are:

- Evaluate a range of power supply/demand options and issues facing HCEA, and
- Develop an integrated resource plan to provide reliable, cost-effective power to its customers over a reasonable planning period.

The objective function used to evaluate alternatives was minimization of total utility costs over the study period. This approach addresses the longer term cost differences between alternatives.

Alternatively, a minimization of average system rate calculations could have been used. The relative rankings of alternatives could change when DSM alternatives are introduced into the analysis. Since most DSM programs reduce sales, the result could be that rates may rise even though total costs decline. This condition occurs when the reduction in costs due to the DSM program is less than the marginal change in revenue as a result of those reduced energy sales.

Load Forecast

The HCEA load forecast was prepared by PSCO in 1995 and is based upon information provided by HCEA. This energy forecast, presented in Exhibit 1, was prepared by customer class and covers a 20-year period, 1996 to 2015. While HCEA had provided power to the Glenwood Springs Electric System in the past, those sales ended in 1996. Therefore, the forecast of energy and demand requirements that has been used in this study exclude any sales by HCEA to the Glenwood municipal system. Table 1 summarizes the energy and system peak demand as used for this study.

Table 1
HOLY CROSS ELECTRIC ASSOCIATION
LOAD FORECAST
Without Glenwood Springs

	Energy Requirements (MWh)	Annual Change	Annual Peak (MW)	Annual Load Factor
Actual				
1993	669,839		157.9	48.43%
1994	693,115	3.47%	158.9	49.78%
1995	721,714	4.13%	167.3	49.25%
Estimated				
1996	739,222	2.43%	169.5	49.79%
1997	763,099	3.23%	174.9	49.79%
1998	787,451	3.19%	180.5	49.79%
1999	812,293	3.15%	186.2	49.79%
2000	837,652	3.12%	192.0	49.79%
2001	861,144	2.80%	197.4	49.79%
2002	885,012	2.77%	202.9	49.79%
2003	909,274	2.74%	208.5	49.79%
2004	933,937	2.71%	214.1	49.79%
2005	959,017	2.69%	219.9	49.79%
2006	982,246	2.42%	225.2	49.79%
2007	1,005,779	2.40%	230.6	49.79%
2008	1,029,623	2.37%	236.0	49.79%
2009	1,053,786	2.35%	241.6	49.79%
2010	1,078,285	2.32%	247.2	49.79%
2011	1,100,974	2.10%	252.4	49.79%
2012	1,123,900	2.08%	257.7	49.79%
2013	1,147,073	2.06%	263.0	49.79%
2014	1,170,499	2.04%	268.3	49.79%
2015	1,194,179	2.02%	273.8	49.79%

Supply-side Screening Analysis

The principal power resource for HCEA is its power supply agreement with PSCO. The key provisions of this contract with PSCO as they relate to HCEA's resources and the IRP process are:

- For at least the first 15 years of the 30-year contract term, PSCO shall provide HCEA's full demand and energy requirements in excess of the preference power from Western, purchases from Qualifying Facilities (QFs) and economy purchases.

- Partial requirements service can be provided by PSCO after the first 15 years, with a year's notice required for each 20% reduction of maximum load that is shifted away from PSCO.

- HCEA may purchase any amount of economy energy from any available source, up to its net system requirements. HCEA will remain liable for the demand charge payable to PSCO based on its total load.

- HCEA may participate in PSCO generation capacity additions, with a maximum capacity participation in a single PSCO project limited to 30% of the projected HCEA system peak demand.

- If a QF locates on the HCEA system and contracts with HCEA for the purchase of its output, HCEA can reduce its purchase of demand and energy from PSCO, commensurate with the purchase from the QF.

- PSCO is to provide annually to HCEA its best estimates of wholesale power rates applicable to Holy Cross for a 10-year period. These rates defini

are intended to be fully-allocated cost based rates approved by the Federal Energy Regulatory Commission (FERC).

Since the contract provides, with few exceptions, that HCEA purchase its full requirements from PSCO through the year 2006, the supply-side options that can be seriously studied over the next 10 years are restricted. In order to exercise control over purchased energy costs, HCEA has been purchasing economy energy from PSCO, PacifiCorp and other utilities at favorable rates compared to the energy costs from PSCO under the power supply agreement. As the wholesale market continues to become more competitive, we believe that HCEA should be able to continue to purchase economy power at favorable rates. It needs to be noted that these purchases still depend upon HCEA's firm purchases of power under the long-term agreement and that the demand charge from PSCO continues to apply to the total load supported by PSCO.

Based on its currently published resource plans which include the repowering of the Ft. St. Vrain facility, PSCO does not have any capacity additions in the form of new plants that HCEA may wish to consider to participate in during the 1997-2006 period. While there could be HCEA participation in wind power or other small renewables projects, the contractual provision will not provide much opportunity for diversification in the near future.

As provided in the contract, PSCO has provided HCEA with its most recent rates for demand and energy for the 10-year period 1996-2005. As a result of the recent FERC rate order, the demand charge was reduced slightly from the previously expected rate of $10.39 per kW per month to $10.22 per kW per month. There are no ratchet or minimum billing demand provisions in the rate. The estimated power rate for the firm purchases from PSCO are summarized in Table 2.

Monthly capacity delivered to the HCEA system from Western ranges from 8.2 MW in December to 4.4 MW in October; energy deliveries also vary on a monthly basis. Power costs for the purchases from Western have been assumed at $3.83 per kW per month for demand and $8.90 per Mwh for energy. These values have been adjusted to reflect transmission system losses.

Table 2
Estimated Cost of Purchased Power
From PSCO

	Demand Charge $/KW-month	Energy Cost $/MWh
1996	10.22	15.70
1997	10.22	16.30
1998	10.22	16.50
1999	10.22	17.00
2000	10.22	16.90
2001	10.22	17.40
2002	10.22	17.70
2003	10.22	18.20
2004	10.22	18.10
2005	10.22	18.70

While the current PSCO contract may limit HCEA's flexibility to participate in new generating resources, a review of other potential options may provide useful information in ensuring that the PSCO contract is competitive with other power supply resources. Specifically, an evaluation was conducted to see whether there are other resource options that could provide HCEA with the capacity and energy at a lower cost than currently being incurred with PSCO. For this effort the planning alternatives described in Table 3 were selected as generic alternatives and reflect data from Stone & Webster's power plant technology database. This database was created using industry publications and Stone & Webster studies. The information in the database represents average conditions and is intended to be used for planning purposes to compare power plant sizes and types.

Table 3
Summary of Planning Alternatives

	Capital Cost $/kW	Fixed O&M $/kW-yr	Variable O&M $/MWh	Heat Rate Btu/kWh
Portion of 440 MW Coal Unit	$1,513	19.89	2.00	9,880
40 MW Combustion Turbine	500	0.56	9.89	10,010
80 MW Combustion Turbine	335	.26	4.02	11,923
Combined Cycle - 62.5 MW	600	17.00	1.81	8,100
Combined Cycle - 120 MW	600	9.00	2.85	6,790
Wind Turbine	1,072	37.00	-	-
Photovoltaics	9,375	10.00	-	-

With the exception of the coal unit, all of the generic units have been assumed to use natural gas, with a 1996 price of $2.10 per MMBtu, while coal costs were set at $1.00 per MMBtu.

An initial screening of the identified options led to the rejection of the wind and photovoltaic options. Under ideal conditions where the hours of operation approach 4,000 per year, the cost of photovoltaic generation will be about 30 cents per kWh or more than 6 times the power cost from PSCO. While wind turbines can operate at an annual capacity factor of 20 percent, the resulting cost of power will still be over 9 cents per kWh. Given that disparity and the cost that HCEA could incur in renegotiating the power contract, those options would not be viable options over the next 10 years.

Table 4
Escalation Rates

	Coal	Gas	GDP Deflator
1997	-0.3	-0.4	2.3
1998	0.1	2.1	2.5
1999	0.6	1.6	2.7
2000	0.9	3.5	2.9
2001	0.9	5.2	3.0
2002	1.5	6.4	3.0
2003	2.3	6.8	3.1
2004	2.5	6.3	3.2
2005	2.5	6.3	3.3
2006	2.2	6.3	3.6

Assumptions

- Escalation - For all generic resources modeled, the capital costs and O&M costs have been supplied in 1996 dollars and the Gross Domestic Product (GDP) deflator would be applied throughout the study to those costs. Escalation rates used in the analysis are summarized in Table 4. These values are based on data presented in the May 1996 issue of Data Resources, Inc.'s (DRI) Review of the U.S. Economy.

- Cost of Money - The weighted cost of capital is used in expansion planning analyses to discount costs to the current year. For this study, a 10.27 percent rate has been used.

- Carrying Charges - A levelized fixed charge rate, representing the annual cost of owning an asset including depreciation, interest, property taxes and a return on equity. For new generation facilities with a 30-year life, a levelized fixed charge rate of 12.298 percent has been used.

- Reliability - The reliability criteria used in the analysis was in accordance with the Inland Power Pool, which requires an 18 percent reserve margin. This reserve margin was applied to new resources added; it is part of the power purchased from Western and PSCO.

Demand-Side Analysis

The analysis of demand-side options was performed in four steps:

- Potential measures were identified.
- The potential measures were screened for cost effectiveness. Surviving measures were combined into programs.
- The developed programs were compared to potential supply resources to develop the integrated resource plan.

Potential Measure Identification

Potential measures were identified based on a review of:

- HCEA's hourly system loads for 1995
- HCEA's monthly rate class level sales for 1995
- Surveys of samples of HCEA's residential and commercial customers performed in 1995.

Based on this review, the following potential measures were identified:

Residential Sector

- Comprehensive audits
- Water heater blankets and pipe insulation on electric water heaters.
- Low flow showerheads and faucet aerators in homes with electric water heating
- Compact fluorescent light bulbs
- Caulking and weatherstripping in electrically heated homes
- Ceiling, wall, and floor insulation in electrically heated homes
- Storm windows in electrically heated homes
- Water heating load control
- Space heating thermostat control

Commercial Sector

Motor efficiency

- Comprehensive audits
- Specialized audits
- Lighting system upgrades
- Measures identified in audits (space heating, air conditioning, refrigeration, cooking, specific processes)

Measure Screening

All of the identified potential measures were evaluated for cost-effectiveness. First, the cost-effectiveness from the total resource cost (TRC) perspective was evaluated. Measures with a TRC benefit-cost ratio below one were dropped from consideration. For the surviving measures, alternative delivery mechanisms or program concepts were developed (e.g., for wall insulation, loans and rebates were considered). Measures with a benefit-cost ratio of at least one from both the Utility Cost and

Participant Cost perspectives for the same program concept were kept for further consideration. For example, for wall insulation the loan concept had benefit-cost ratios exceeding one from both perspectives; but the rebate concept did not pass the Utility Cost Test (UCT) (large enough rebates to induce participation cost too much; smaller rebates did not induce enough participation to pay for the program's fixed costs).

As a result of this two-stage screening, the following measures were dropped from consideration, for the reasons indicated:

Residential Sector

- Storm windows – failed TRC
- Water heating load control – passed TRC; so many curtailments were required per month that (a) with small discounts, customers would leave the program, and (b) at large discounts, the program failed UCT.
- Space heating thermostat control – same as water heating load control.

Commercial Sector

- Audits – low expected savings from installation of identified measures made the audits themselves not cost-effective.
- Lighting system upgrades – failed TRC due to low coincidence of savings with HCEA's monthly system peaks.
- Other measures identified in audits – several individual measures passed the TRC, but most failed for the same reason as lighting

upgrades; the total savings of cost-effective measures were not large enough to cover the program fixed costs.

Program Development

The following measures, all in the residential sector, survived the cost-effectiveness screening process:

- Comprehensive audits
- Water heater blankets and pipe insulation on electric water heaters
- Low flow showerheads and faucet aerators in homes with electric water heating
- Compact fluorescent light bulbs
- Caulking and weatherstripping in electrically heated homes
- Ceiling, wall, and floor insulation in electrically heated homes

The philosophy used to combine measures into programs, and to design the programs, was to maximize customer adoption of applicable measures, subject to keeping the program cost-effective from HCEA's perspective. For the measures other than insulation, the measure costs are small, but arranging for separate installation or relying on customers to install the measures themselves involves a significant enough hassle factor that not all eligible customers would install the measures. The best program design was therefore to install these measures at no cost to the customer as part of the audit. This design minimizes hassles for the customer, and therefore maximizes measure adoption; and the design is still cost-effective from HCEA's perspective.[3] These measures were therefore combined with the audit into a single program.

Similarly, for the insulation measures, the largest rebates consistent with being cost-effective from HCEA's perspective, would induce only 75-90% adoption among eligible audit participants. A loan program with the load percentage less than 95% also induced significantly less than universal measure adoption. The 95% loan program was therefore selected in order to maximize measure adoption. Because the three individual measures are installed by the same types of contractors, and the loan processing is identical for all three measures, these measures were combined into a single program.

Demand-Side Resources

The integrated resource plan includes two demand-side management (DSM) programs. The following paragraphs describe these programs and the analysis that was performed to select these programs.

Program Descriptions

The two programs are:

1. Residential audit/free installation program – Under this program HCEA staff would perform comprehensive audits of electrically heated homes at no charge to the customer. The auditor would install, again at no cost to the customer, the following measures:

    - Up to five compact fluorescent lightbulbs (CFL)

?

- For homes with electric water heating, a water heater blanket and pipe insulation, up to 529 low-flow showerheads, and up to four faucet aerators, if not already present

- Weatherstripping and caulking, as required.

In addition, the auditor would identify additional measures whose installation could reduce the household's electricity consumption, and inform the household about the likely cost and bill savings of each identified measure. Finally, the auditor would inform residents about the second program.

The program would be marketed primarily through bill stuffers, as well as periodic articles in HCEA's newsletter. In addition, as part of the program local contractors would be recruited to promote the program, in return for referrals and eligibility for the second program.

2. Residential insulation loan program – Under this program, HCEA would provide loans to participants in the audit program:

    - For whom installation of ceiling, wall, and/or floor insulation was identified as cost-effective in the audit, and

    - who install the recommended insulation.

HCEA will loan customers up to 95% of the cost of materials and contractor labor. The loans would be repaid over five years, and would carry an interest rate equal to HCEA's cost-of-borrowing plus 1.375% (approximately 12%). Only measures installed by contractors certified by HCEA would be eligible for loans.

Approximately 6,900 of HCEA's approximately 32,000 residential customers use electricity as their primary space heating fuel. Of these 6,900 customers eligible for audits, it is anticipated that 200 will request audits each year. Free measures will be installed in all residences where they are applicable. It is anticipated that all recommended insulation measures will be installed; the 95% loans for these measures reduces the payback on these measures to one year or less. Thus, the expected numbers of installations of all measures are limited only by their technical applicability. Table 5 summarizes the expected annual measure installations under the two programs and associated first-year impacts. The expected annual cost of the Audit/Free Install Program is $39,121, all borne by HCEA. This cost includes 12% of the cost of the audit labor, the cost of the installed measures under administration costs. The expected annual cost to HCEA of the loan program is $77,233, which includes 88% of the cost of the audit labor plus administration costs. In addition, each year HCEA will loan customers $207,513. The first-year cost of the loan program to customers is $10,922, equal to 5% of the cost of the installed measures. In addition, customers will borrow, and repay over the ensuing five years, $207,513 in each program year.

Table 5
Expected Annual Measure Installations and First-Year Impacts

Measure	Number Installed	Impacts: Annual Energy (kWh)	Impacts: Winter Demand (kW)	Measure Life (Years)
Audit/Free Install Program				
CFL Package	160	48,356	23	5
WH Blanket/Pipe Insulation	118	69,264	15	10
Low Flow Fixture Package	118	69,264	15	10
Caulking/Weatherstripping	120	153,139	62	5
Total		340,023	115	
Insulation Load Program				
Ceiling	144	467,152	191	30
Wall	68	330,874	135	30
	72	292,349	119	30
Total		1,090,376	445	

Table 6 shows that both programs pass the three cost-effectiveness tests commonly used to evaluate energy efficiency programs. The loans and loan repayments do not affect the Total Resource Cost Test, because these are transfer payments between HCEA and customers. For the utility cost test, the loan is a cost, and the loan repayment a benefit. For the Participant Cost Test, the loan reduces the initial cost (i.e., only 5% of the measure costs are counted as costs) and the loan repayment is a cost.

Table 6
Cost-Effectiveness Tests – One Year of Program Operation

	Audit/Free Install	Insulation Loan
Total Resource Cost Perspective		
Gross Benefits	$62,413	$454,191
Costs	39,121	295,668
Net Benefits	23,292	158,523
Benefit/Cost	1.60	1.54
Utility Cost Perspective		
Gross Benefits	$62,413	$672,412
Costs	39,121	284,746
Net Benefits	23,292	387,666
Benefit/Cost	1.60	2.56
Participant Cost Perspective		
Gross Benefits	$90,018	$470,184
Costs	0	203,893
Net Benefits	90,018	266,292
Benefit/Cost	N/A	2.31

Integration Analysis

The electric utility resource planning process has evolved from evaluation of the economics and timing of future unit installations to a much more sophisticated analysis of all practical alternative resources, including those that reduce electric energy consumption. The term "resource" now connotes a wide range of demand-side and supply-side options. Traditional resource planning was essentially confined to preparing load forecasts and matching load with new capacity to achieve a reliability index. The reasons for the transition to an integrated supply-demand analysis include recognition of the value of conservation, the rising cost of new power plants, a more competitive marketplace, the promotion of greater efficiency in energy use, and environmental concerns.

The integration analysis is based on the premise that the DSM and supply-side resources should compete on a "level playing field". Thus the screened DSM resources are allowed to compete equally with the supply-side generation alternatives in the capacity expansion planning process. If DSM resources result in lower overall costs, their inclusion or exclusion in the resource plan will be automatic and they will be brought into the resource mix at the optimal time and to an optimal degree.

The objective of the integration process was to determine the most economically feasible resources, either demand- or supply-side options to be added to HCEA's system in order to meet future demand and maintain system reliability. The integration process concentrates on these four areas:

- optimization of the mix, size, and timing of options to determine several resource plans,
- derivation of resource plans according to several conflicting objective functions,
- insurance of equal reliability for all plans whether DSM or supply-side options are included, and
- incorporation of the hourly effects of DSM programs, program costs, revenue impacts, and market penetration rates.

The integrated resource analysis utilized Electric Power Research Institute's (EPRI's) Electric Generation Expansion Analysis System (EGEAS) model. This model incorporates generation expansion capabilities as well as detailed production costing capabilities. EGEAS has specific features to accommodate purchased power transactions, which include monthly generation, capacity, and energy costs.

The system was dispatched on the EGEAS model for a 11-year planning horizon (1996-2006) with a 20-year extension period, serving HCEA's projected loads. During the 20-year extension period, the fuel dispatch was the same as the last year of the planning horizon, but with the costs escalated. Results have been presented for both the 11-year period as well as the overall 31-year period. Expansion plans were developed using EGEAS's Dynamic Programming capabilities. This process was used to evaluate up to 10 planning alternatives simultaneously.

The least costly scenario was calculated and the sizing and timing of generating unit additions, power purchases or DSM options were reported. These plans were printed out in order of cumulative net present value of future revenue requirements. The different plans were then analyzed to determine the relationship between the alternatives.

Public Participation

During the preparation of the IRP, HCEA advertised in local media for the public to participate in the process. At the four meetings that were held, there was a minimal level of participation by the public. In addition, in 1995 HCEA sought public input through a customer survey that was designed to get strategic information about HCEA's customers and to identify perceived weaknesses in its operations. Based on these efforts, the most significant concerns are the reliability at the distribution voltage level and the interest in purchasing power from renewable sources such as wind turbines, so-called "green" power. Recognizing that some of its customers are willing to pay higher rates for power generated from renewables, HCEA is exploring an option where residential customers could pay a nominal amount each month which would allow them to receive 200 kWh. The additional charge would contribute to the additional cost of the wind power relative to the cost of purchased power from PSCO.

Results of Integration Analysis

The results of the IRP analysis indicate that for the 11 year period, 1996-2006, the PSCO contract is the least cost supply-side alternative on a present worth of revenue requirements basis. At the same time, the DSM alternatives that were evaluated are also economically attractive. The following table summarizes the present worth of revenue requirements for both the base case and with three different DSM programs Two comparisons have been presented in the table. The first is a short-term one covering the base 11-year study period, while the long term comparison includes a 20 year extension period to capture the full effects of long term investments. While the results suggest that HCEA embark directly on the insulation program. However, the audit program is the process where leads for the insulation program are developed. Since these two are complementary, we recommend that they be pursued as a part of a combined program.

Table 7
Comparison of Total Revenue Requirements

	Study Period Present Worth of Costs ($Million)	Difference From Base	Long-Term Present Worth of Costs ($Million)	Difference From Base
Base Case - Continue PSCO Purchases	$201.463	-	$310.582	-
DSM Audit Program with Reduced PSCO Purchases	201.408	0.03%	310.295	0.10%
Insulation Program with Reduced PSCO Purchases	199.441	1.00%	306.227	1.40%
Audit Program and Insulation Program with Reduced PSCO	199.421	1.00%	305.978	1.48%

Implementation Plans - 2 and 5 year

The results of the basic IRP indicate that the current PSCO contract should be maintained in its present form. The other supply-side resources result in substantially higher total costs and when coupled with the costs for renegotiating the PSCO agreement, would not result in any savings in the near term. However, inasmuch as the two DSM programs appear to be cost effective, we recommend that the audit program be developed in 1997, with the first audits starting in the summer of 1997. As the audit effort continues with about 200 residential dwellings done each year, the effort for the second program, to improve the insulation of electrically heated homes will be done in large part by the auditors. Over the first two years, the target should be for about 300 residential dwellings audited and with about half of that number receiving the insulation loan during that period.

At the same time, the special wind power rate should be marketed to determine if there is adequate interest in the region to support the local development of one or more wind turbines. If there is interest, then HCEA may want to participate in the deployment of wind power.

Environmental

HCEA does not operate any production facilities, but purchases its energy requirements from other utilities. A portion of these purchases are from Western and are hydro-based. The balance of the energy purchases are from PSCO under the long-term agreement or from other regional generating facilities. For purposes of this IRP, the continuation of the power supply agreement leaves the issues of emission controls, costs considerations of emissions options, and environmental compliance with the owners and operators of the generating facilities. To the extent that the IRP has recommended certain DSM programs that will reduce both peak demand and annual energy requirements with the result that power purchases will be reduced from PSCO, there should be a corresponding decline in environmental emissions from PSCO's thermal plants.

Exhibit E

2004 HCE Load Forecast Summary

LOAD FORECAST STUDY
HOLY CROSS ELECTRIC ASSOCIATION, INC.
DBA: HOLY CROSS ENERGY
FIFTEEN YEAR HISTORY: 1990– 2004
TWENTY YEAR FORECAST: 2005 – 2024

COLORADO 34 EAGLE

APPROVED BY:

HOLY CROSS ENERGY

____

Thomas Turnbull, President   Date

APPROVED BY:

HOLY CROSS ENERGY

____

Kent Benham, Chief Executive Officer   Date

HOLY CROSS ELECTRIC ASSOCIATION, INC.
Colorado 34 Eagle
LOAD FORECAST STUDY

Background

Holy Cross Energy (HCE) operates an electrical distribution system serving approximately 50,500 meters in the counties of Garfield, Eagle, Pitkin and small portions of Gunnison and Mesa in Western Colorado. The service area ranges from high plains plateaus to mountain peaks with population centers in the mountain valleys of the Colorado, Eagle, Roaring Fork, and Crystal Rivers. Elevations rise from 4,000 feet to 12,000 feet above sea level. Precipitation varies from 10 inches per year at lower elevations to over 25 inches in the higher elevations. Annual mean temperature for the area is approximately 43 degrees, and annual heating degree days range from 6,600 to over 8,000.

The economic base of the area is largely dependent upon the year round recreation tourist industry. The location and climate lends itself to many types of outdoor recreation such as winter sports, hunting, fishing, and sightseeing. Holy Cross serves several ski resorts including the world famous developments at Vail, Beaver Creek, Aspen, and Snowmass. As the recreation industry has expanded over the past thirty years, so did the cities, towns, villages, and rural areas to provide necessary housing, goods, and services needed by both the tourist and permanent resident.

HCE currently purchases firm power for its distribution customers from two sources. A portion of its firm electrical power requirements is provided under a contract with the Western Area Power Administration (WAPA), and the balance is purchased under a contract with Public Service Company of Colorado (PSCO).

Recent events and developments continue to provide growth in the Holy Cross service territory. A gradual transition toward a "four-season" status is taking place within the resort areas. This transition helps provide load diversity and improvement of the annual load factor.

Current power requirements of HCE and its customers in excess of the WAPA allotment (and excluding economy power purchases and purchases from Qualifying Facilities, if any) is provided by PSCO under the current power supply contract, which will essentially provides most of the full requirements of HCE. PSCo can terminate this contract in 2020. Holy Cross can ramp out of this contract any time after January 1st of 2005. See attached ramp out provision.

The Holy Cross Study

Holy Cross staff performed the forecast modeling for this study. The methodology is recapped below:

1. **Energy Forecast**

Historical data was compiled from the Rural Utilities Services (RUS) Form 7 monthly sales and customer data that break down energy sales into major categories. Forecasts were then created and summarized for each of the major categories.

The primary forecasting tool was econometric information provided by Woods and Poole Economics, Inc. out of Washington, D. C. This database provides categories including household, population, and employment growth by county forecasted to the year 2030. The econometric data was used to forecast customer growth in the residential and commercial classes, which accounts for the majority of Holy Cross energy needs.

Residential

Annual energy sales were calculated by the following method:

SALES = (KWH_PER_CUS) times (NUM_CUS)

Where

SALES: Annual forecasted residential sales

KWH_PER_CUS: The weather normalized annual usage per residential customer was calculated using the following steps:

a. The average fifteen year annual heating degree days was calculated from monthly data provided by National Oceanic and Atmospheric Administration for Eagle, Colorado.

b. An average residential consumer kWh per heating degree factor was calculated from historical data.

c. The average fifteen year number of heating degree days was then multiplied times the average residential consumer kWh per heating degree day to arrive at weather normalized usage per residential customer. The annual usage per customer was held constant over the forecast period.

NUM_CUS: The average annual number of residential customers. The starting point was actual year end 2004 residential customers in Eagle, Garfield, and Pitkin counties. The Woods and Poole growth rate for the number of households for each of the respective counties was applied and then summed to obtain the total forecasted number of Holy Cross residential customers.

Commercial

The rate classes for small commercial (1000 KVA or less), large commercial (over 1000 KVA), and irrigation were combined. The current rate structure provides for customer migration between the commercial classes to provide the most advantageous rate for the customer. HCE has only a handful of irrigation customers, most of which are golf courses. Irrigation is not a significant load.

The forecasting method for commercial was the same as for residential except Woods and Poole employment growth was used to forecast commercial customer growth.

Lighting

Public Street and Highway Lighting is not a significant load. Using 15 year historical data, growth was projected to continue at a rate of 2%.

Company Use

Company use is not a significant load (approximately .2% of total load). It was assumed to remain constant through out the forecast period. Any growth was assumed to be offset by conservation measures.

Losses

Losses as a percent of sales were forecasted to be 4.84% throughout the study period.

High and Low Forecasts

High and low forecasts were computed at a growth rate of .5% plus or minus from the base forecasts.

2. Peak Demand Forecast

The 2005 Holy Cross peak demand occurs primarily in December. The peak demand growth has been slower than energy growth since 1996; however, the growth of peak demand has increased over the past four years. For this study purpose, the assumption was made to forecast demand growth at the energy growth rate.

Holy Cross designs its distribution system to meet the winter peaks. Summer peak growth has increased at a rate faster than energy growth due to an increase in summer recreation; however, Holy Cross's summer peak is only 55% of the winter peak. Therefore, the summer peak growth forecast is not particularly important at this time.

Summary and Results

Exhibit 1

The Base Forecast Table contains kWh sales data for residential, commercial, and lighting classes. Company use and losses were added to sales to arrive at total annual energy usage. Actual residential sales in 2004 were projected to grow at rates beginning at 3.22% in 2005, and declining to 1.71% by 2024. Commercial growth begins at 3.31% in 2005, declining to 2.03% by 2024. Lighting is projected to maintain the historic annual growth rate of 2%. Company use is expected to remain stable at 0% growth, with any potential increase offset by conservation measures. Losses are forecasted to be 4.84%.

Holy Cross Energy's total net energy requirement for the forecast period is projected to increase 3.46%, declining to 1.87% by 2024. For the period this is a compounded growth rate of 2.57%. Peak demand is assumed to grow at the same rate as energy.

Exhibits 2 and 3

The High and Low Forecast Tables use the base assumptions, increased or decreased respectively by a factor of .5%.

Exhibits 4 and 5

The Energy Forecast and Peak Demand Forecast graphs show the base, high, and low projections of energy and demand requirements through 2024, with 9 years of historic information.

Exhibit 6

The graph of Power Requirements Growth Rates shows the expected gradual decline of the forecasted growth rate, with 8 years of historic data.

Exhibit 7

This graph visually shows the historic relationship between consumer usage and heating degree days.

Exhibit 8

This graph compares the 1998 Power Requirements Study to the 2005 PRS. The 2005 forecast reflects the Woods and Poole expectation that growth in Eagle and Garfield counties will remain robust longer than was projected in 1998.

Exhibits 9 and 10

These graphs show historic consumer and usage growth by class.

Exhibit 11

This table shows historic kWh sales, company use, losses and demand from 1990 – 2004.

Exhibit 12

Holy Cross ramp out clause from its PSCO power purchase agreement.

Base Forecast Table

	2004 Actual	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Sales (kwh)											
Residential	502,553,652	518,712,059	534,944,521	551,123,467	567,204,309	583,248,358	599,221,125	615,087,182	630,810,296	646,353,566	661,761,711
Commercial	490,951,923	507,213,682	525,583,744	543,950,647	562,252,482	580,589,700	598,917,599	617,189,715	635,358,000	653,373,027	671,361,752
Lighting	1,188,007	1,218,000	1,242,360	1,267,207	1,292,551	1,318,402	1,344,770	1,371,666	1,399,099	1,427,081	1,455,623
Total Sales	994,693,582	1,027,143,741	1,061,770,625	1,096,341,321	1,130,749,342	1,165,156,461	1,199,483,494	1,233,648,562	1,267,567,395	1,301,153,674	1,334,579,086
Company Use	1,945,679	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000
Losses	46,221,944	49,808,137	51,484,078	53,157,300	54,822,648	56,487,953	58,149,381	59,802,970	61,444,642	63,070,218	64,688,008
Total purchases (kwh)	1,042,861,205	1,078,901,879	1,115,204,703	1,151,448,620	1,187,521,990	1,223,594,413	1,259,582,875	1,295,401,533	1,330,962,037	1,366,173,892	1,401,217,094
% Growth		3.46%	3.36%	3.25%	3.13%	3.04%	2.94%	2.84%	2.75%	2.65%	2.57%
Peak Summer Demand (kw)	118,418	122,510	126,633	130,748	134,844	138,940	143,027	147,094	151,132	155,130	159,110
% Growth		3.46%	3.36%	3.25%	3.13%	3.04%	2.94%	2.84%	2.75%	2.65%	2.57%
Peak Winter Demand (kw)	226,995	234,840	242,742	250,631	258,483	266,334	274,168	281,964	289,705	297,369	304,997
% Growth		3.46%	3.36%	3.25%	3.13%	3.04%	2.94%	2.84%	2.75%	2.65%	2.57%

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Sales (kwh)										
Residential	677,003,550	692,047,489	706,861,636	721,413,911	735,844,947	750,133,581	764,258,447	778,198,030	791,930,722	805,434,877
Commercial	689,289,070	707,118,896	724,814,277	742,337,515	759,808,311	777,199,760	794,484,394	811,634,247	828,620,931	845,415,715
Lighting	1,484,735	1,514,430	1,544,719	1,575,613	1,607,125	1,639,268	1,672,053	1,705,494	1,739,604	1,774,396
Total Sales	1,367,777,355	1,400,680,815	1,433,220,632	1,465,327,040	1,497,260,384	1,528,972,609	1,560,414,894	1,591,537,771	1,622,291,257	1,652,624,987
Company Use	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000
Losses	66,294,804	67,887,331	69,462,259	71,016,209	72,561,783	74,096,654	75,618,461	77,124,808	78,613,277	80,081,429
Total purchases (kwh)	1,436,022,159	1,470,518,147	1,504,632,890	1,538,293,248	1,571,772,166	1,605,019,263	1,637,983,355	1,670,612,579	1,702,854,534	1,734,656,417
% Growth	2.48%	2.40%	2.32%	2.24%	2.18%	2.12%	2.05%	1.99%	1.93%	1.87%
Peak Summer Demand (kw)	163,062	166,979	170,853	174,675	178,476	182,252	185,995	189,700	193,361	196,972
% Growth	2.48%	2.40%	2.32%	2.24%	2.18%	2.12%	2.05%	1.99%	1.93%	1.87%
Peak Winter Demand (kw)	312,573	320,081	327,507	334,834	342,121	349,357	356,533	363,635	370,653	377,575
% Growth	2.48%	2.40%	2.32%	2.24%	2.18%	2.12%	2.05%	1.99%	1.93%	1.87%

Exhibit 1.

High Case Forecast Table

	2004 Actual	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Sales (kwh)											
Residential	502,553,652	521,224,828	540,142,047	559,178,898	578,290,678	597,539,773	616,891,621	636,310,012	655,757,183	675,193,934	694,665,562
Commercial	490,951,923	509,668,442	530,675,751	551,873,977	573,201,771	594,762,096	616,511,197	638,402,624	660,387,369	682,414,019	704,614,373
Lighting	1,188,007	1,218,000	1,242,360	1,267,207	1,292,551	1,318,402	1,344,770	1,371,666	1,399,099	1,427,081	1,455,623
Total Sales	994,693,582	1,032,111,269	1,072,060,159	1,112,320,082	1,152,785,001	1,193,620,271	1,234,747,588	1,276,084,301	1,317,543,651	1,359,035,034	1,400,735,558
Company Use	1,945,679	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000
Losses	46,221,944	49,808,137	51,484,078	53,157,300	54,822,648	56,487,953	58,149,381	59,802,970	61,444,642	63,070,218	64,688,008
Total purchases (kwh)	1,042,861,205	1,083,869,406	1,125,494,237	1,167,427,382	1,209,557,649	1,252,058,224	1,294,846,969	1,337,837,271	1,380,938,292	1,424,055,252	1,467,373,566
% Growth		3.93%	3.84%	3.73%	3.61%	3.51%	3.42%	3.32%	3.22%	3.12%	3.04%
Peak Summer Demand (kw)	118,418	123,075	127,801	132,563	137,347	142,173	147,031	151,913	156,807	161,703	166,622
% Growth		3.93%	3.84%	3.73%	3.61%	3.51%	3.42%	3.32%	3.22%	3.12%	3.04%
Peak Winter Demand (kw)	226,995	235,921	244,981	254,109	263,279	272,530	281,844	291,201	300,583	309,968	319,397
% Growth		3.93%	3.84%	3.73%	3.61%	3.51%	3.42%	3.32%	3.22%	3.12%	3.04%

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Sales (kwh)										
Residential	714,138,577	733,578,400	752,949,461	772,215,301	791,523,635	810,851,055	830,173,474	849,466,172	868,703,849	887,860,673
Commercial	726,952,705	749,391,539	771,891,735	794,412,584	817,081,021	839,868,806	862,746,520	885,683,621	908,648,502	931,608,555
Lighting	1,484,735	1,514,430	1,544,719	1,575,613	1,607,125	1,639,268	1,672,053	1,705,494	1,739,604	1,774,396
Total Sales	1,442,576,017	1,484,484,369	1,526,385,914	1,568,203,498	1,610,211,782	1,652,359,129	1,694,592,047	1,736,855,288	1,779,091,955	1,821,243,625
Company Use	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000
Losses	66,294,804	67,887,331	69,462,259	71,016,209	72,561,783	74,096,654	75,618,461	77,124,808	78,613,277	80,081,429
Total purchases (kwh)	1,510,820,821	1,554,321,701	1,597,798,172	1,641,169,707	1,684,723,564	1,728,405,783	1,772,160,508	1,815,930,096	1,859,655,232	1,903,275,054
% Growth	2.96%	2.88%	2.80%	2.71%	2.65%	2.59%	2.53%	2.47%	2.41%	2.35%
Peak Summer Demand (kw)	171,555	176,495	181,432	186,357	191,302	196,262	201,231	206,201	211,166	216,119
% Growth	2.96%	2.88%	2.80%	2.71%	2.65%	2.59%	2.53%	2.47%	2.41%	2.35%
Peak Winter Demand (kw)	328,854	338,322	347,786	357,226	366,706	376,214	385,738	395,265	404,783	414,277
% Growth	2.96%	2.88%	2.80%	2.71%	2.65%	2.59%	2.53%	2.47%	2.41%	2.35%

Exhibit 2.

Low Case Forecast Table

Sales (kwh)	2004 Actual	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Residential	502,553,652	516,199,291	529,772,122	543,145,773	556,278,110	569,231,709	581,974,458	594,473,989	606,697,811	618,613,456	630,267,249
Commercial	490,951,923	504,758,923	520,516,284	536,103,519	551,460,812	566,688,768	581,744,402	596,583,866	611,162,655	625,435,831	639,528,207
Lighting	1,188,007	1,218,000	1,242,360	1,267,207	1,292,551	1,318,402	1,344,770	1,371,666	1,399,099	1,427,081	1,455,623
Total Sales	994,693,582	1,022,176,214	1,051,530,767	1,080,516,499	1,109,031,473	1,137,238,879	1,165,063,631	1,192,429,521	1,219,259,565	1,245,476,368	1,271,251,079
Company Use	1,945,679	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000
Losses	46,221,944	49,808,137	51,484,078	53,157,300	54,822,648	56,487,953	58,149,381	59,802,970	61,444,642	63,070,218	64,688,008
Total purchases (kwh)	1,042,861,205	1,073,934,351	1,104,964,845	1,135,623,799	1,165,804,121	1,195,676,831	1,225,163,012	1,254,182,492	1,282,654,207	1,310,496,586	1,337,889,087
% Growth		2.98%	2.89%	2.77%	2.66%	2.56%	2.47%	2.37%	2.27%	2.17%	2.09%
Peak Summer Demand (kw)	118,418	121,946	125,470	128,951	132,378	135,770	139,119	142,414	145,647	148,808	151,919
% Growth		2.98%	2.89%	2.77%	2.66%	2.56%	2.47%	2.37%	2.27%	2.17%	2.09%
Peak Winter Demand (kw)	226,995	233,759	240,513	247,186	253,755	260,258	266,676	272,992	279,190	285,250	291,212
% Growth		2.98%	2.89%	2.77%	2.66%	2.56%	2.47%	2.37%	2.27%	2.17%	2.09%

Sales (kwh)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Residential	641,632,364	652,682,146	663,390,218	673,730,589	683,839,123	693,698,712	703,292,427	712,603,567	721,615,710	730,312,761
Commercial	653,407,836	667,042,484	680,399,755	693,447,221	706,300,156	718,935,342	731,329,520	743,459,456	755,302,013	766,834,232
Lighting	1,484,735	1,514,430	1,544,719	1,575,613	1,607,125	1,639,268	1,672,053	1,705,494	1,739,604	1,774,396
Total Sales	1,296,524,936	1,321,239,060	1,345,334,692	1,368,753,423	1,391,746,404	1,414,273,322	1,436,294,000	1,457,768,516	1,478,657,327	1,498,921,390
Company Use	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000	1,950,000
Losses	66,294,804	67,887,331	69,462,259	71,016,209	72,561,783	74,096,654	75,618,461	77,124,808	78,613,277	80,081,429
Total purchases (kwh)	1,364,769,740	1,391,076,391	1,416,746,950	1,441,719,632	1,466,258,186	1,490,319,976	1,513,862,461	1,536,843,324	1,559,220,603	1,580,952,819
% Growth	2.01%	1.93%	1.85%	1.76%	1.70%	1.64%	1.58%	1.52%	1.46%	1.39%
Peak Summer Demand (kw)	154,971	157,958	160,873	163,709	166,495	169,227	171,901	174,510	177,051	179,519
% Growth	2.01%	1.93%	1.85%	1.76%	1.70%	1.64%	1.58%	1.52%	1.46%	1.39%
Peak Winter Demand (kw)	297,063	302,789	308,377	313,813	319,154	324,391	329,516	334,518	339,389	344,119
% Growth	2.01%	1.93%	1.85%	1.76%	1.70%	1.64%	1.58%	1.52%	1.46%	1.39%

Exhibit 3

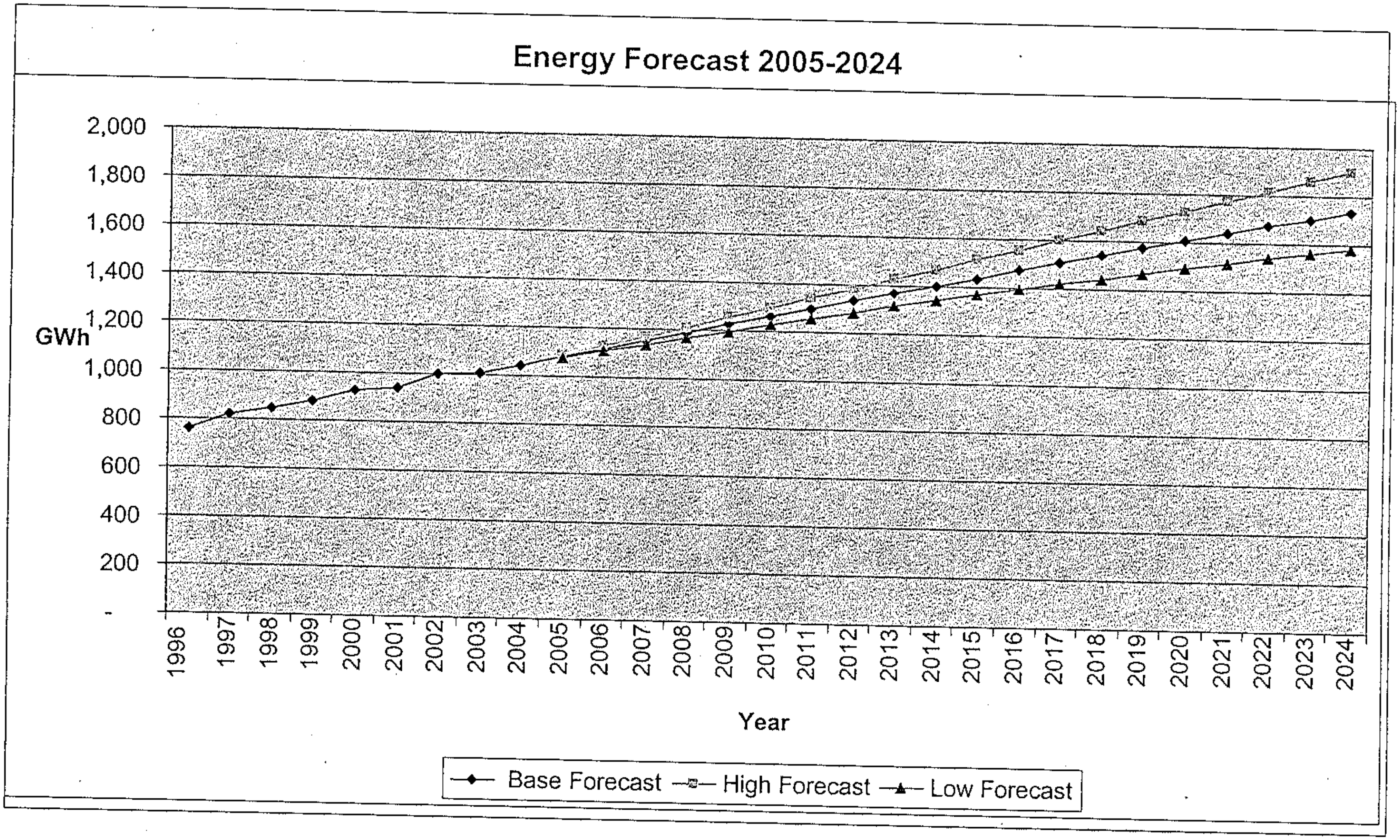
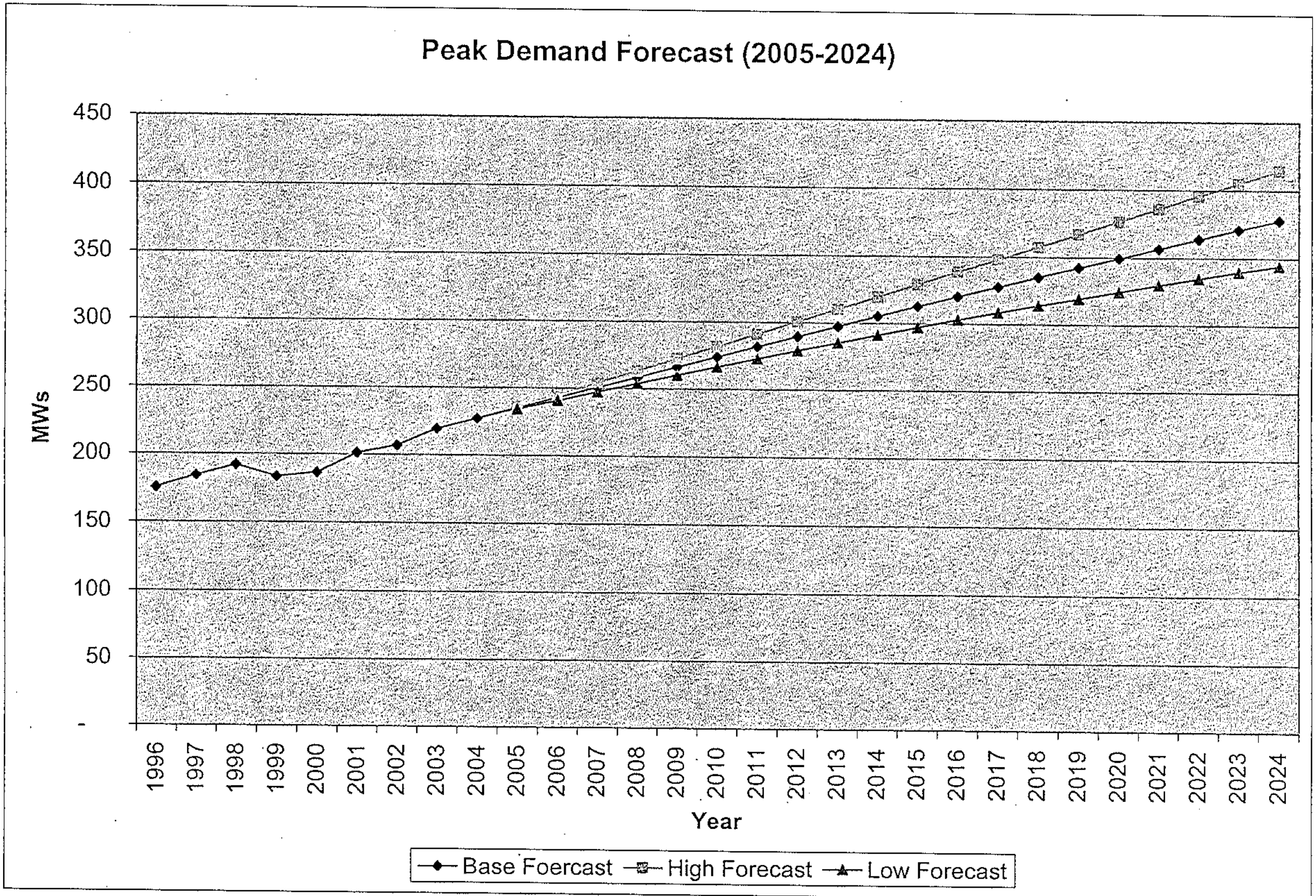
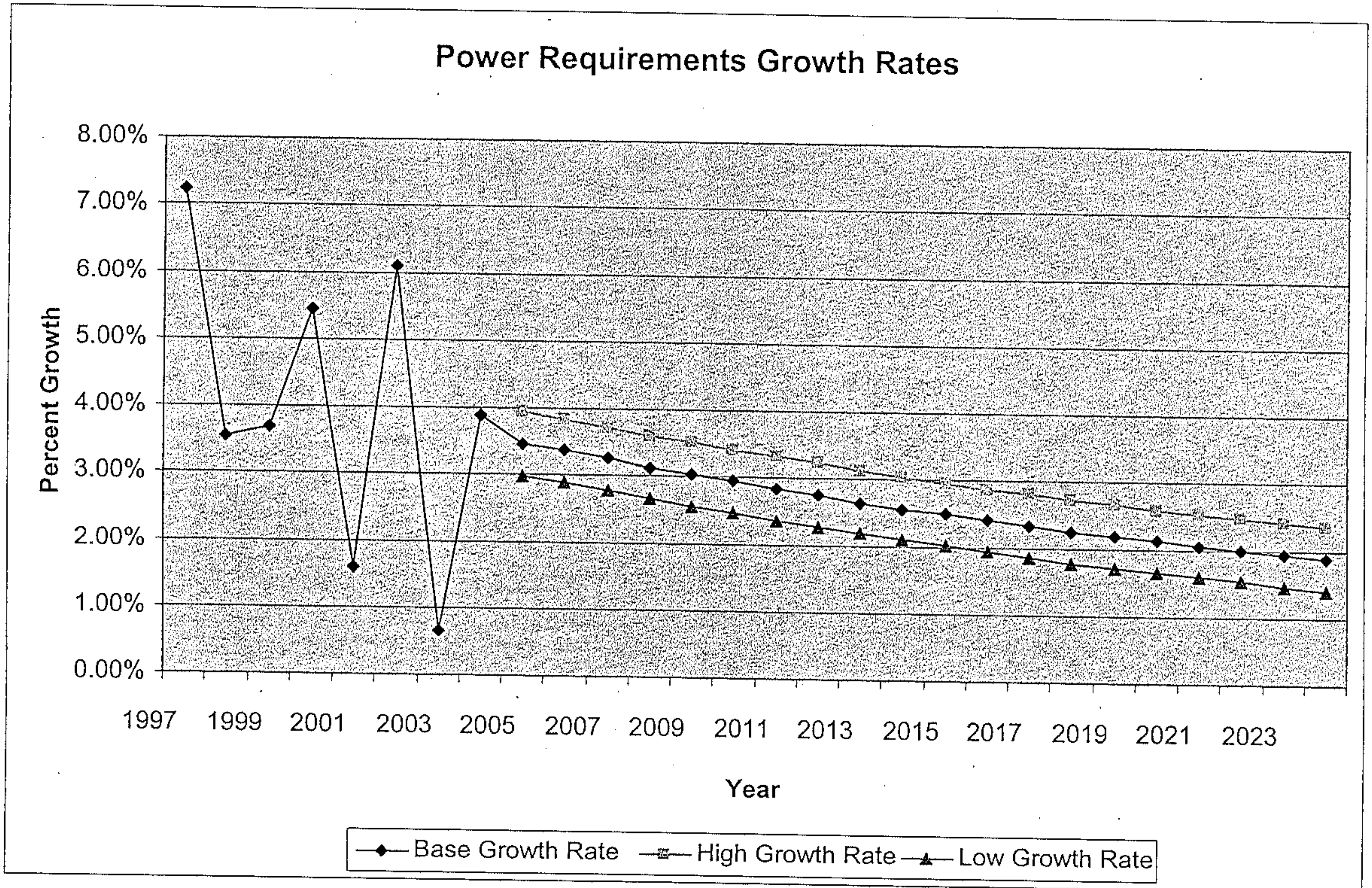

Energy Forecast 2005-2024
GWh
2,000
1,800
1,600
1,400
1,200
1,000
800
600
400
200
-
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
Year
Base Forecast
High Forecast
Low Forecast

Exhibit 4



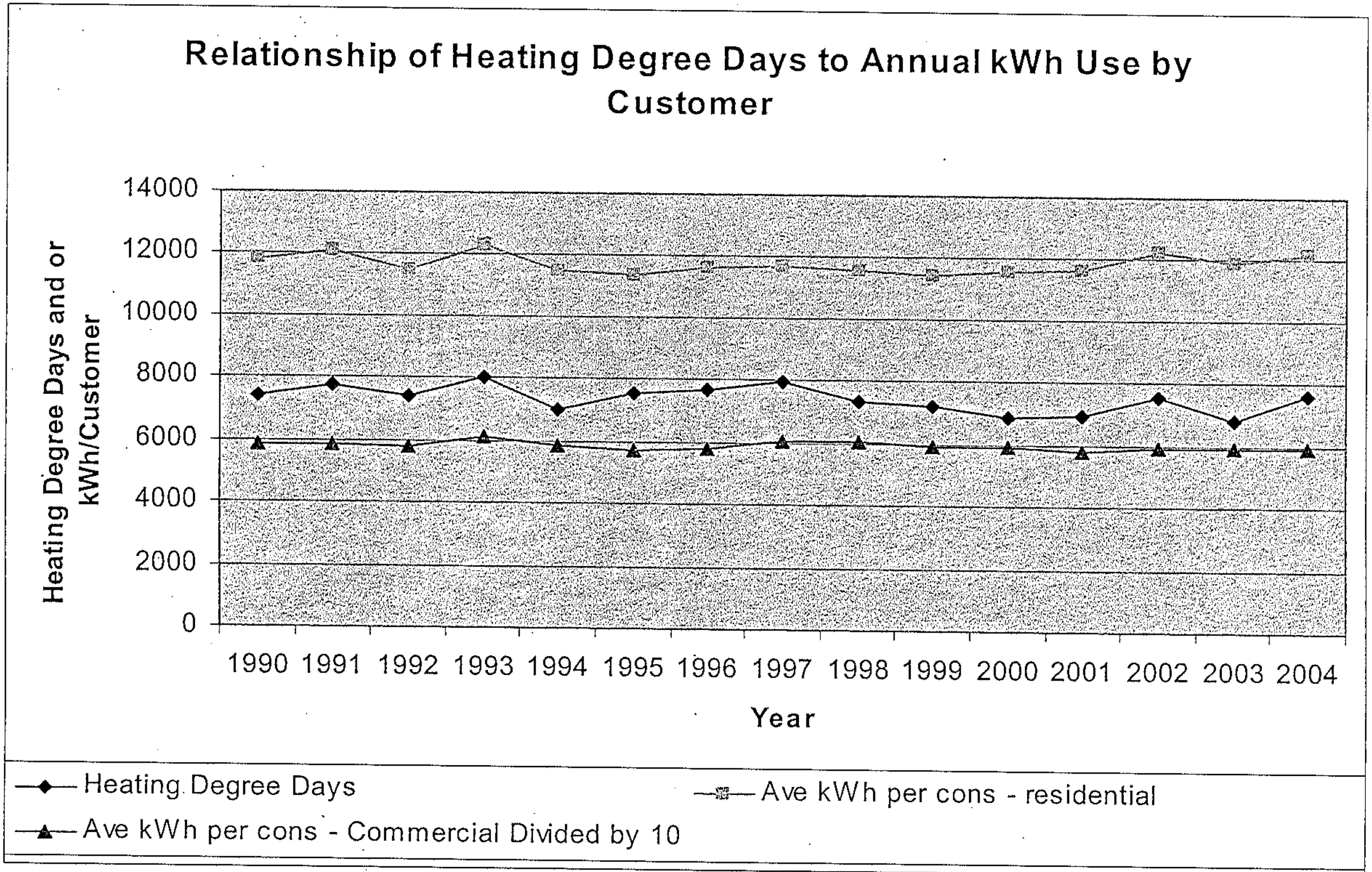
Peak Demand Forecast (2005-2024)
MWs
450
400
350
300
250
200
150
100
50
-
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
Year
Base Foercast
High Forecast
Low Forecast

Exhibit 5



Power Requirements Growth Rates
8.00%
7.00%
6.00%
5.00%
4.00%
3.00%
2.00%
1.00%
0.00%
Percent Growth
1997
1999
2001
2003
2005
2007
2009
2011
2013
2015
2017
2019
2021
2023
Year
Base Growth Rate
High Growth Rate
Low Growth Rate

Exhibit 6



Relationship of Heating Degree Days to Annual kWh Use by Customer
Heating Degree Days and or kWh/Customer
14000
12000
10000
8000
6000
4000
2000
0
1990 1991 1992 1993 1994 1995 1996 1997 1998 1999 2000 2001 2002 2003 2004
Year
Heating Degree Days
Ave kWh per cons - residential
Ave kWh per cons - Commercial Divided by 10

Exhibit 7

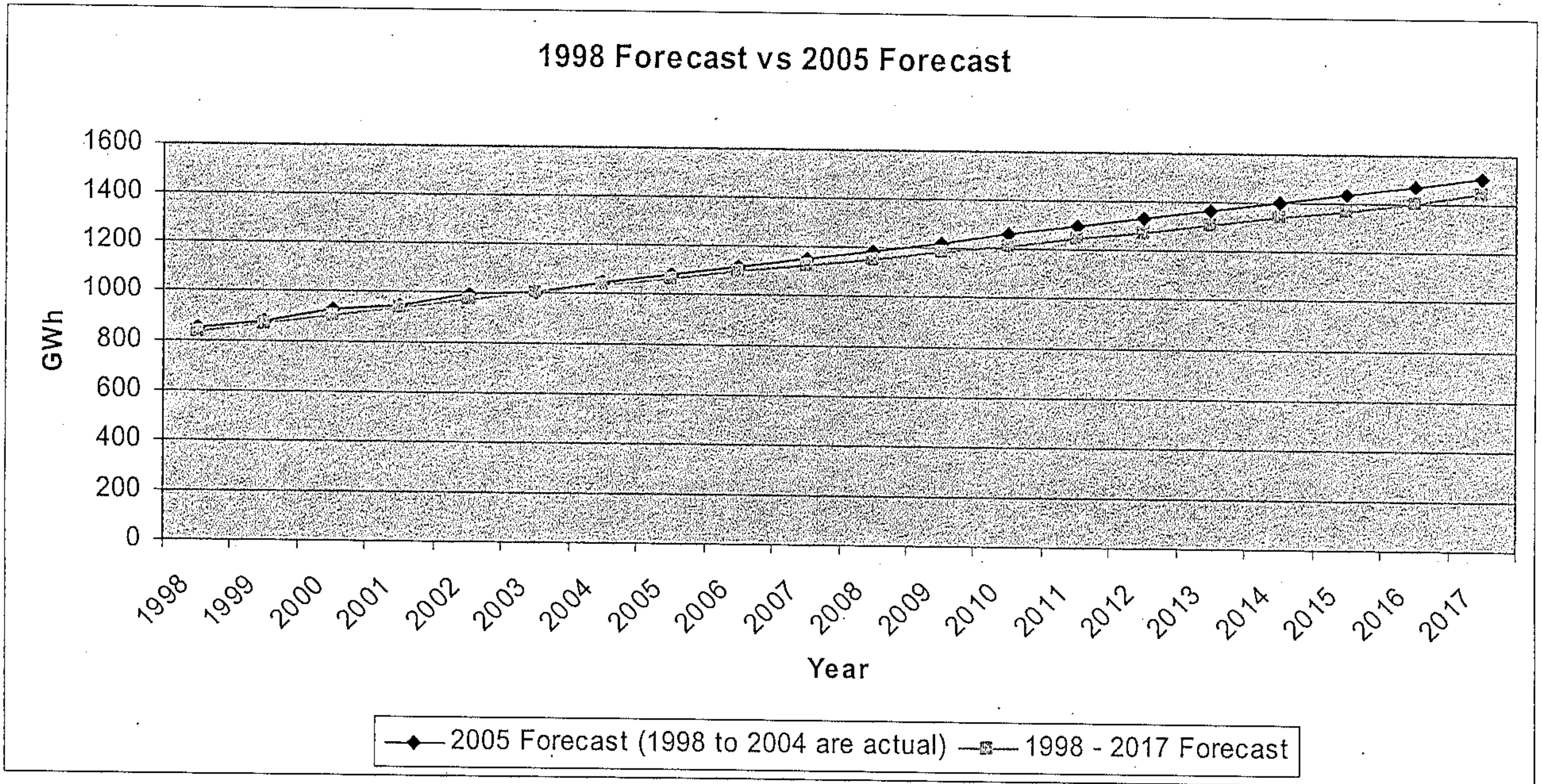

1998 Forecast vs 2005 Forecast
GWh
1600
1400
1200
1000
800
600
400
200
0
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
Year
2005 Forecast (1998 to 2004 are actual)
1998 - 2017 Forecast

Exhibit 8.

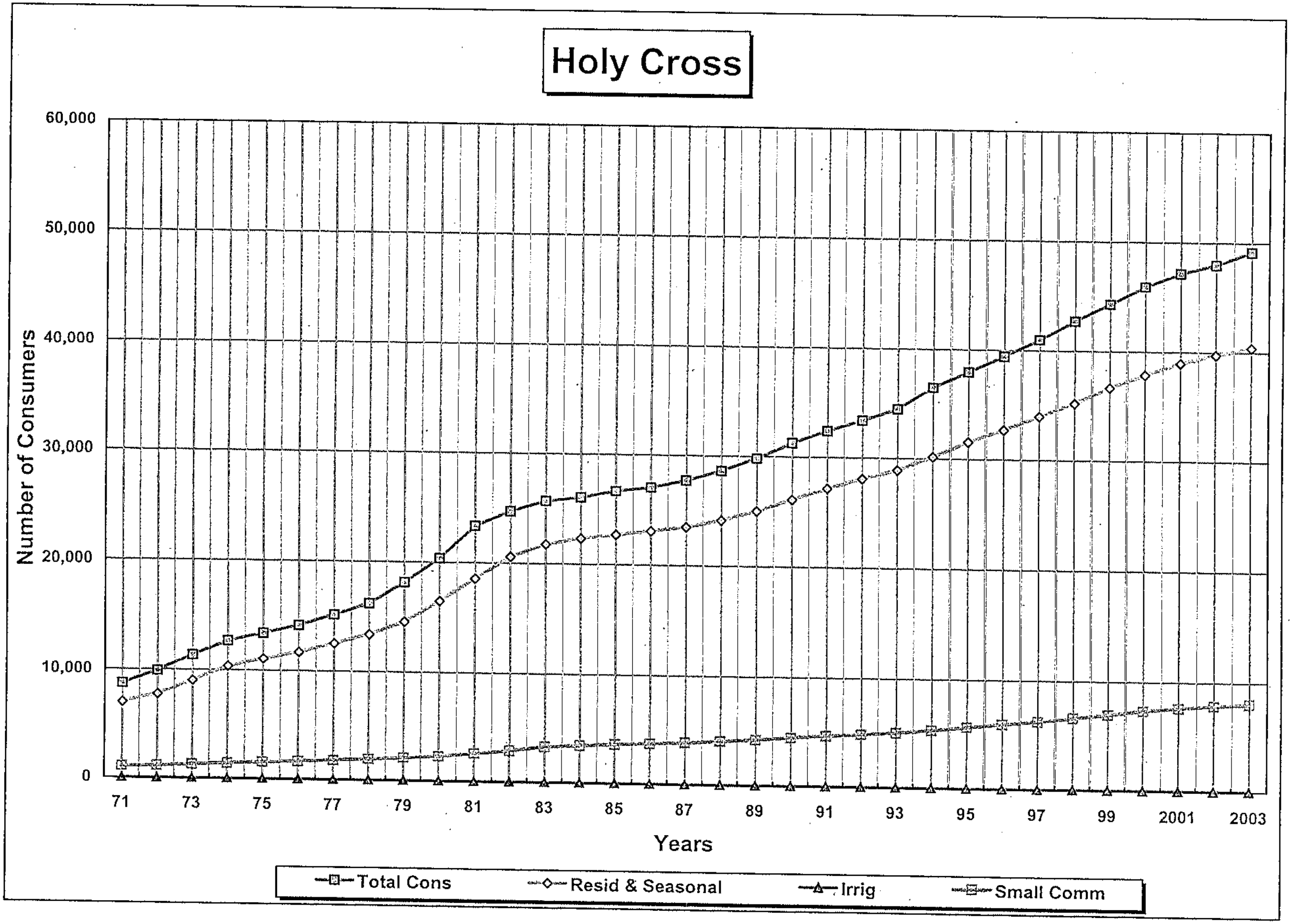

Holy Cross
Number of Consumers
60,000
50,000
40,000
30,000
20,000
10,000
0
71
73
75
77
79
81
83
85
87
89
91
93
95
97
99
2001
2003
Years
Total Cons
Resid & Seasonal
Irrig
Small Comm

Exhibit 9

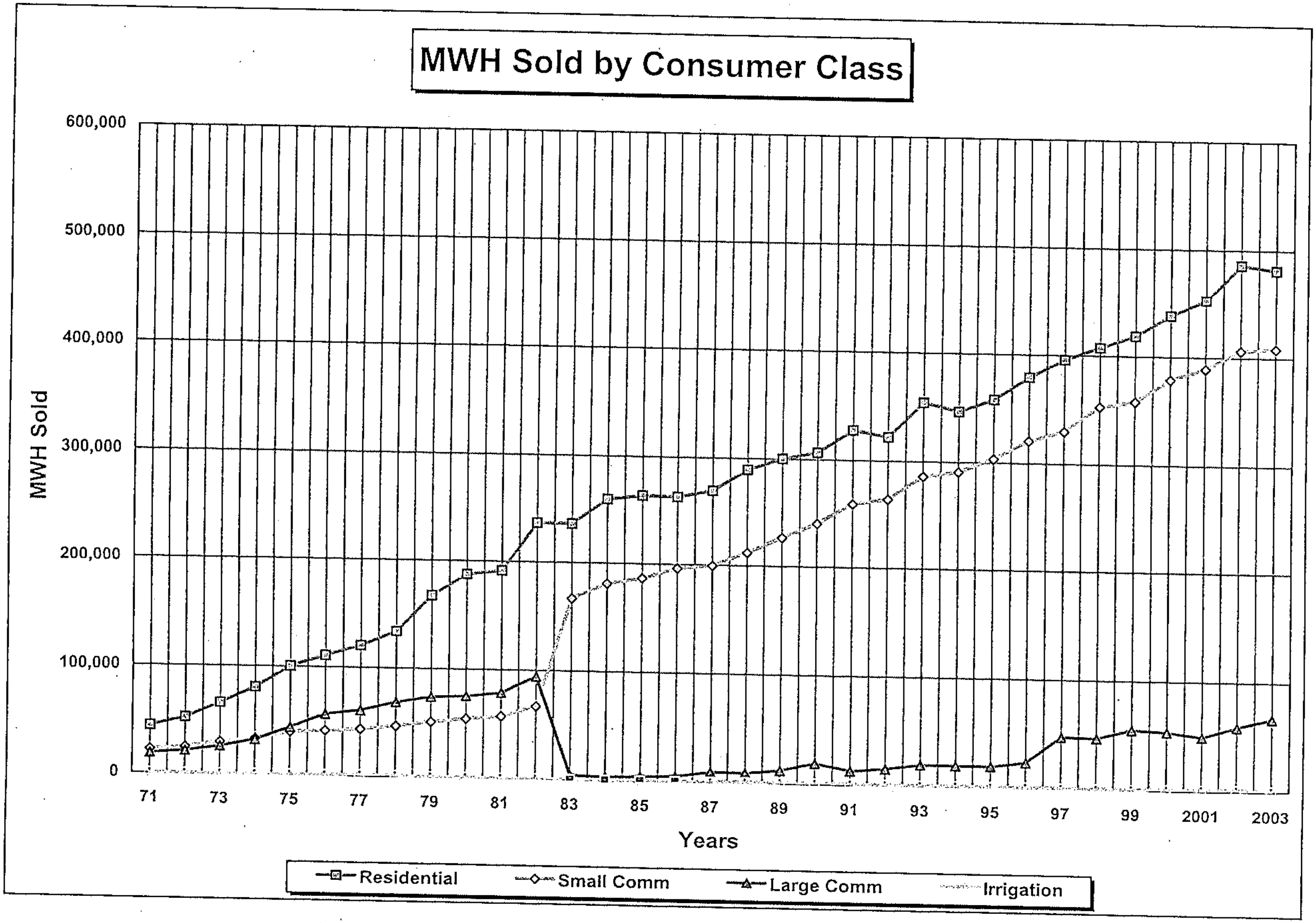

MWH Sold by Consumer Class
600,000
500,000
400,000
300,000
200,000
100,000
0
MWH Sold
71
73
75
77
79
81
83
85
87
89
91
93
95
97
99
2001
2003
Years
Residential
Small Comm
Large Comm
Irrigation

Exhibit 10

Historical Growth Summary

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Sales (kwh)										
Residential	306,347,285	327,317,302	321,554,176	354,285,372	346,384,004	358,232,399	379,223,779	395,829,837	407,579,288	418,889,560
% Growth		6.85%	-1.76%	10.18%	-2.23%	3.42%	5.86%	4.38%	2.97%	2.77%
Commercial	260,512,541	272,605,233	280,107,300	306,218,046	311,121,121	323,410,433	344,626,078	377,399,903	400,586,681	413,764,164
% Growth		4.64%	2.75%	9.32%	1.60%	3.95%	6.56%	9.51%	6.14%	3.29%
Lighting	900,995	930,205	927,535	929,290	945,980	963,782	989,660	1,006,653	1,036,370	1,079,979
% Growth		3.24%	-0.29%	0.19%	1.80%	1.88%	2.69%	1.72%	2.95%	4.21%
Total Sales	567,760,821	600,852,740	602,589,011	661,432,708	658,451,105	682,606,614	724,839,517	774,236,393	809,202,339	833,733,703
% Growth		5.83%	0.29%	9.77%	-0.45%	3.67%	6.19%	6.81%	4.52%	3.03%
Company Use	1,569,110	1,749,382	1,552,017	1,640,704	1,744,796	1,815,508	2,044,793	2,155,046	2,129,139	2,043,015
% Growth		11.49%	-11.28%	5.71%	6.34%	4.05%	12.63%	5.39%	-1.20%	-4.05%
Losses	31,509,544	25,606,922	29,202,999	6,765,587	32,900,024	37,291,364	35,322,597	40,988,057	34,978,538	41,642,388
% of Sales	5.55%	4.26%	4.85%	1.02%	5.00%	5.46%	4.87%	5.29%	4.32%	4.99%
Total purchases (kwh)	600,839,475	628,209,044	633,344,027	669,838,999	693,095,925	721,713,486	762,206,907	817,379,496	846,310,016	877,419,106
% Growth		4.56%	0.82%	5.76%	3.47%	4.13%	5.61%	7.24%	3.54%	3.68%
Peak Summer Demand (kw)	69,664	73,527	75,219	83,758	86,312	96,474	82,761	88,553	93,064	97,302
% Growth		5.55%	2.30%	11.35%	3.05%	11.77%	-14.21%	7.00%	5.09%	4.55%
Peak Winter Demand (kw)	184,485	163,181	161,150	169,463	171,955	181,418	175,125	184,020	191,953	188,388
% Growth		-11.55%	-1.24%	5.16%	1.47%	5.50%	-3.47%	5.08%	4.31%	-1.86%

	2000	2001	2002	2003	2004	Compounded Growth Rate
Sales (kwh)						
Residential	438,185,008	453,027,770	485,947,098	481,316,728	502,553,652	3.60%
% Growth	4.61%	3.39%	7.27%	-0.95%	4.41%	
Commercial	433,351,967	439,383,336	467,011,941	476,011,255	490,951,923	4.63%
% Growth	4.73%	1.39%	6.29%	1.93%	3.14%	
Lighting	1,105,501	1,155,688	1,197,582	1,205,773	1,188,007	1.99%
% Growth	2.36%	4.54%	3.63%	0.68%	-1.47%	
Total Sales	872,642,476	893,566,794	954,156,621	958,533,756	994,693,582	4.09%
% Growth	4.67%	2.40%	6.78%	0.46%	3.77%	
Company Use	2,153,541	2,275,569	1,992,286	1,925,949	1,945,679	1.55%
% Growth	5.41%	5.67%	-12.45%	-3.33%	1.02%	
Losses	50,453,848	44,114,291	41,067,913	43,288,521	46,221,944	
% of Sales	5.78%	4.94%	4.30%	4.52%	4.65%	
Total purchases (kwh)	925,249,865	939,956,654	997,216,820	1,003,748,226	1,042,861,205	4.02%
% Growth	5.45%	1.59%	6.09%	0.65%	3.90%	
Peak Summer Demand (kw)	106,396	107,978	111,742	116,326	118,418	3.86%
% Growth	9.35%	1.49%	3.49%	4.10%	1.80%	
Peak Winter Demand (kw)	186,429	200,940	206,409	219,114	226,995	1.49%
% Growth	-1.04%	7.78%	2.72%	6.16%	3.60%	

Exhibit 11

5.3 Partial Requirements Service Option.

Holy Cross may convert any Point(s) of Delivery served under this Agreement to Partial Requirements Service, with such service to commence at any time after December 31, 2004. If Holy Cross elects to convert to Partial Requirements Service, it shall give Public Service notice of the Point(s) of Delivery which will be converted to Partial Requirements Service, and the amount by which it proposes to reduce its Full Requirements Service purchases from Public Service. The notice required shall be a function of the proposed level of reduction of total load supplied by Public Service in accordance with the following schedule:

Minimum Notice	Percent of Maximum Load Reduction
12 Months	20%
24 Months	40%
36 Months	60%
48 Months	80%
60 Months	100%

If Holy Cross elects to convert to Partial Requirements Service, Public Service shall make available to Holy Cross a Partial Requirements Service rate. If the parties cannot agree on the appropriate Partial Requirements Service rate, Public Service shall make the appropriate filing with the FERC seeking implementation of a Partial Requirements Service rate, and Holy Cross shall have the right to contest such filing.

Exhibit F

2007 HCE Customer Survey & Results

HOLY CROSS ENERGY

A Touchstone Energy® Cooperative

2007 Customer Survey

July 2007

GDS Associates, Inc.

Table of Contents

1 Executive Summary

Holy Cross Energy (HCE) conducted the 2007 Consumer Survey in May 2007. The survey was designed to investigate consumer attitudes and opinions regarding HCE's power supply mix, environmental stewardship, renewable resources, bill payment options, and satisfaction with Holy Cross management and operations. This report presents the key findings of the survey, a comparison of the 2003 and 2007 surveys, and the methodology employed in conducting the survey. The appendix contains the questionnaire and the detailed cross-tabulations of results.

1.1 Key Findings

The 2007 survey addressed five areas: power supply mix, renewable resources, energy conservation, bill payment options, and the HCE report card. Analysis of the survey results reveals the following:

- **As in the 2003 survey, reliability of electric service is the most important factor to consumers with respect to HCE's power supply mix.**
- **Consumers strongly favor increasing the percentage of renewable resources in HCE's power supply mix, even to the extent of increasing rates.**
- **Consumers continue to look for ways to conserve energy and increase energy efficiency.**
- **Regarding bill payment options, consumers most favor mail/postal service, automatic payment by credit card, and E-bills. Least favorable options are paying in person at HCE, an HCE drop box, and automated telephone (credit card). Consumers are indifferent to convenience pay locations (kiosks at various outlets).**
- **Consistent with the 2003 survey, consumers indicate HCE is providing reliable electric service**.

1.2 Summary Results

Details providing support of the conclusions presented above for each of the areas researched during the study are as follows:

Power Supply Mix Considerations – Reliability of electric service is the most important factor to consumers regarding power supply mix, followed by environmental impacts of power supply mix. Cost is the least important factor.

Issue	Percent
Reliability of service	43%
Environmental impacts of power supply mix	33%
Cost of electricity to members	24%

Renewable Resources – Consumers strongly favor the development of renewable resources within the service territory. The strongest preference is for wind power, followed by power generated from photovoltaic, hydroelectric, and biomass resources.

Resource	Percent
Wind	79%
Photovoltaic	71%
Hydroelectric	65%
Biomass	58%

Percentages based on consumers that "Strongly Agree" and "Agree"

Renewable Resource Electricity Costs – Overall, consumers indicated a willingness to pay nearly eight percent more for their electricity if the percentage of renewable resources in HCE's power supply mix were to increase.

Increase	Percent
No increase	8%
Less than 2%	11%
2% - 5%	24%
6% - 10%	28%
11% - 15%	14%
16% - 20%	15%
Average rate increase	7.7%

If HCE were to increase rates to fund certain programs, consumers favor increasing the percentage of renewable resources and increasing energy efficiency and conservation programs more than purchasing Renewable Energy Credits (RECs) or increasing power supply purchases from cleaner burning fossil fueled plants.

Renewable Energy Fund – Approximately three out of every four consumers favor a surcharge to their monthly power bill that would be earmarked for funding of a large scale renewable resource generation project in HCE's service territory.

Level of Agreement	Percent
Strongly agree/Agree/Agree somewhat	74%
Strongly disagree/Disagree/Disagree somewhat	26%

Bill Payment Options – Mail/Postal service is still by far the preferred bill payment method. Web-based alternatives and automatic deductions from credit cards and checking accounts comprise the second level of preference.

Bill Payment Option	Score
Mail/Postal service	6.5
Automatic payment by credit card	5.4
E-bill (credit card or check)	5.3
Automatic deduct from checking account	5.1
Holy Cross web site (credit card)	4.7
Convenience pay location (kiosk)	2.9
Drop box at the cooperative	2.5
Telephone (recorded instructions)	2.5
In person at the cooperative	1.9

Scores based on 1 to 10 level of preference (10=most preferable)

Holy Cross Report Card – Of the 14 report card issues, consumers rated HCE the highest on the utility's ability to provide reliable service.

Report Card Issue	2003	2007
Providing reliable electric service	5.4	5.5
Rates for electricity have increased very little over the past ten years	4.7	4.4
Keeping customer informed on issues regarding the cooperative	5.1	4.9
Comfortable with the planning decisions made by HCE	5.1	4.9
Priority on environmental stewardship through programs and actions	4.7	4.7
Obtains sufficient consumer input before making decisions on key issues	n/a	4.5
Easy in contacting HCE to answer questions	5.1	5.0
Electric bill is easy to read and understand	5.3	5.4
Patronage allocations and patronage refunds are important	n/a	4.6

Scores based on 1 to 6 scale (6=agree very strongly, 1=disagree very strongly)

The 2003 and 2007 surveys included four questions requested by NRECA, which were included in the report card section of the questionnaire.

NRECA Issue	2003	2007
Considering all your experiences to date with HCE, how satisfied you are with HCE?	8.6	8.7
Extent to which HCE has exceeded your expectations?	7.3	7.2
Imagine an ideal utility company. How well does HCE compare to that ideal utility?	8.1	8.1
Given a choice, how likely it is that you would choose HCE from among other utilities?	8.4	8.3

1.3 Sample Characteristics

The sample was designed to represent all local, year round customers receiving electric service on rate codes 1 through 52. 2,709 questionnaires were mailed to sample customers, 36 of which were returned as undeliverable. 349 valid responses were collected from the survey by the June 1, 2007 deadline, resulting in a response rate of just over 13 percent. The level of precision achieved for this survey is ±5.6 percent at the 95 percent confidence level for results based on 349 respondents.

Representation of the sample in terms of geographic location and average kWh consumption was excellent; therefore, results were not weighted to account for differences between population and sample distributions. Comparisons of population and sample distributions are presented as follows:

Response by County

County	Population	Sample	Difference
Pitkin	24.0%	25%	1%
Eagle	63.0%	59%	-4%
Garfield	13.0%	16%	3%
	100%	100%	

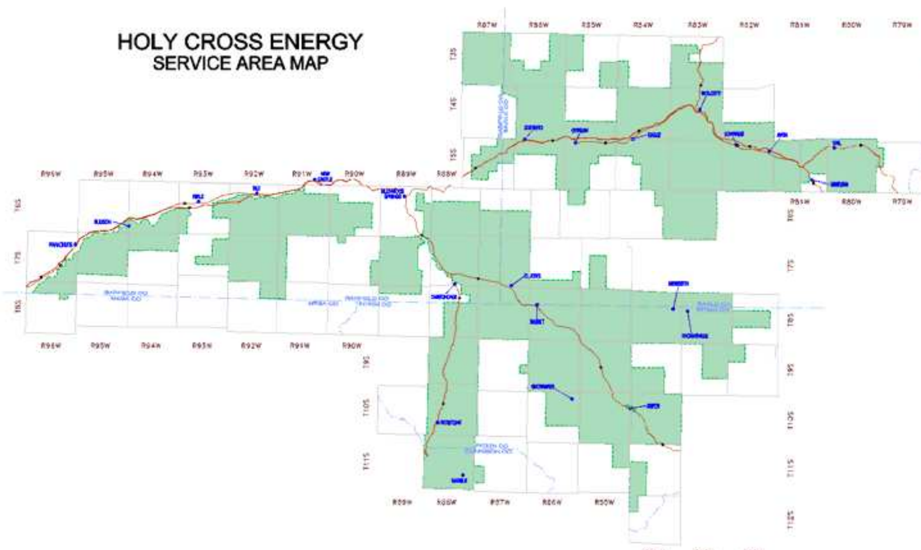
Response by Average kWh Consumption

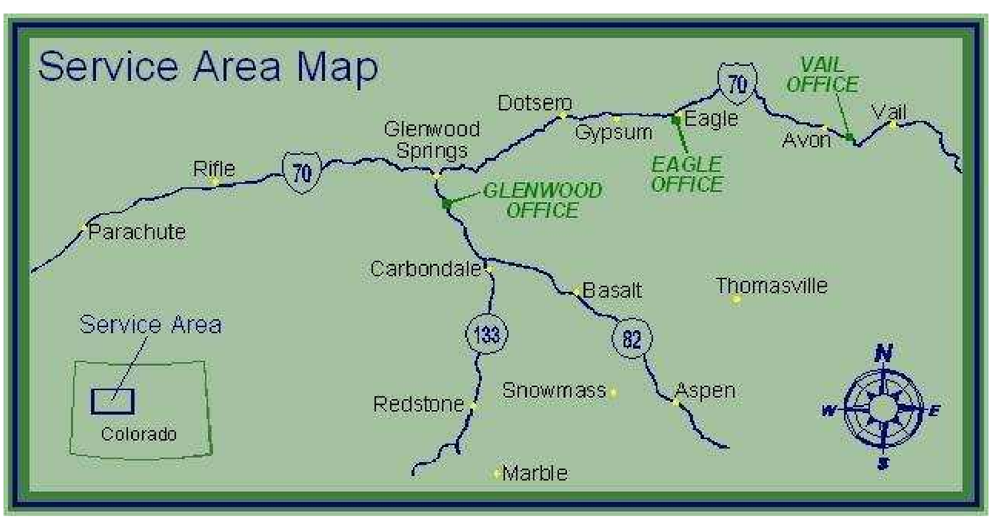
	Population	Sample	Difference
Average Monthly kWh per Customer	1,208	1,254	3.8%

2 General Background

2.1 Service Area

Holy Cross Energy (HCE), headquartered in Glenwood Springs, Colorado, is an electric distribution cooperative serving residential and business customers in western portions of the state, including Eagle, Garfield, Gunnison, Mesa, and Pitkin counties.[1] HCE has nearly 39,000 active member-owners, roughly 53,000 meters, and is served by approximately 164 employees. HCE provides energy and services to major ski resorts located in the Aspen and Vail areas as well as farms, ranches and friendly rural communities that provide people and resources for the tourist and outdoor recreation industries.





[1] HCE billing records contain permanent customer billing addresses in all 50 states and 18 countries.

2.2 HCE Planning Issues

HCE continually evaluates its power supply options for the future, including how best to structure existing contracts that may be renewed, developing new resources, and establishing relationships with existing and new power suppliers. One key component of the decisions made regarding new resources revolves around the components of HCE's power supply portfolio. Currently, HCE's power supply portfolio consists of power generated from coal (55%), natural gas (24%), a market blend of coal and natural gas (15%), and renewable resources (6%).

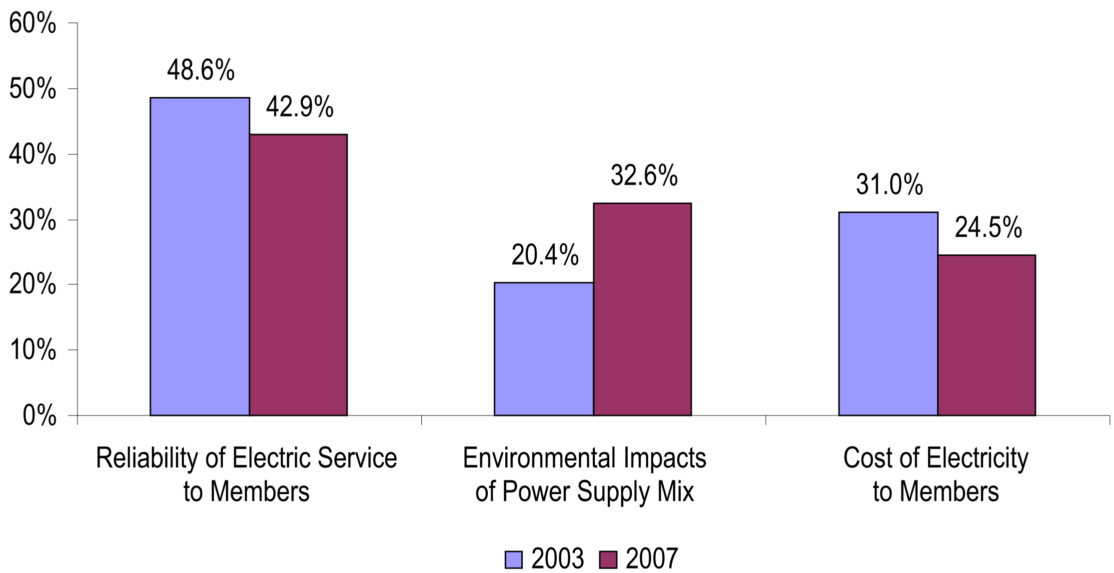
In efforts to collect customer attitudes and opinions regarding key planning issues, surveys are conducted to develop information that is otherwise not available. This 2007 survey addresses issues regarding customer attitudes and opinions on HCE's power supply mix, development of renewable resources, alternative bill payment options, and HCE management and operations. A similar survey was conducted during 2003. HCE continues to evaluate its power supply options for the future in connection with Colorado Amendment 37 and House Bill 1281, which created and revised respectively, a Renewable Energy Standard that imposes new renewable energy requirements on utilities in the state.

3 Analysis of Results

The survey was designed to collect a considerable amount of specific information that is otherwise not available; therefore, the output provided is voluminous. This section of the report summarizes the major findings of the survey, and to the extent possible, compares like questions to the 2003 survey. Detailed data tabulations are presented in the Appendix.

The survey results were analyzed in aggregate and at the county, customer class, and energy use sectors. The energy use categories are high (average monthly consumption exceeds 1,100 kWh), mid (average monthly consumption falls between 601 and 1,100 kWh), and low (average monthly consumption is less than 600 kWh). Approximately one-third of all customers fall in each energy use category.

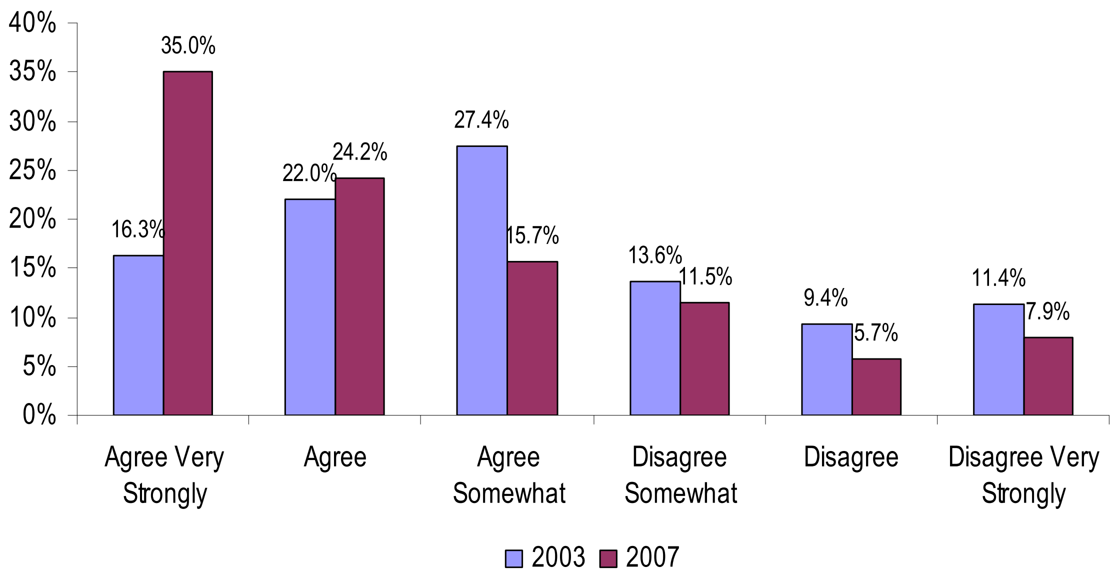
Question 1 – Ranking the importance of key aspects of HCE's power supply mix

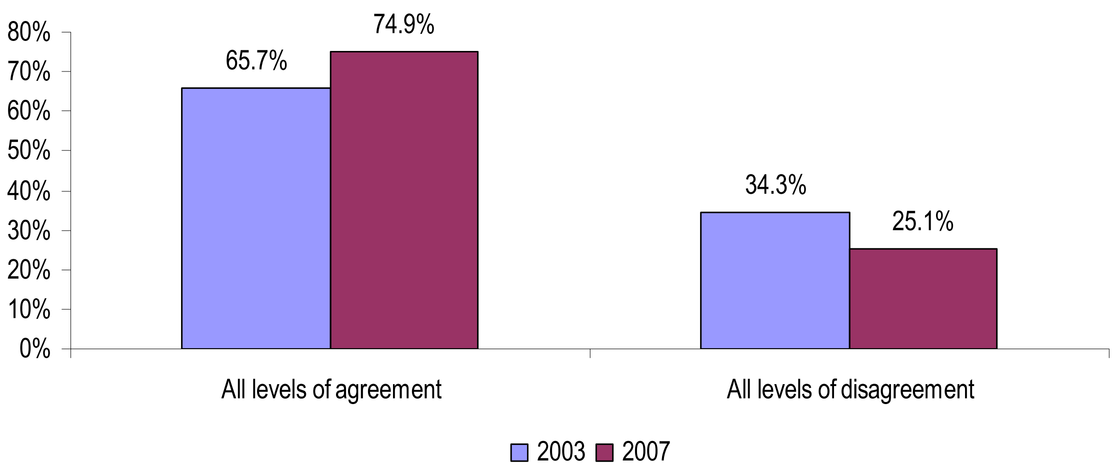


At 42.9%, all customers rank "Reliability of Electric Service" as the most important aspect of HCE's power supply mix, followed by "Environmental Impacts" at 32.6% and "Cost of Electricity to Members" at 24.5%. Customers in Eagle County rank reliability significantly higher than do customers in Pitkin and Garfield counties. Since the 2003 survey, cost has become less of an issue, while environmental impacts have become more important to customers.

Question 2 - Holy Cross should purchase more of its power supply from power plants that incorporate new technologies (including carbon removal) that produce cleaner burning of fossil fuels, even if it increases my electric rates.

35.0% of all customers agree very strongly, and 74.9% agree at any level that HCE should purchase more of its power supply from power plants that incorporate new technologies that produce cleaner burning of fossil fuels, even if it increases rates. Since the 2003 survey, there has been a significant increase in the percentage of customers willing to accept higher electricity costs in order for HCE to acquire “cleaner” electricity.

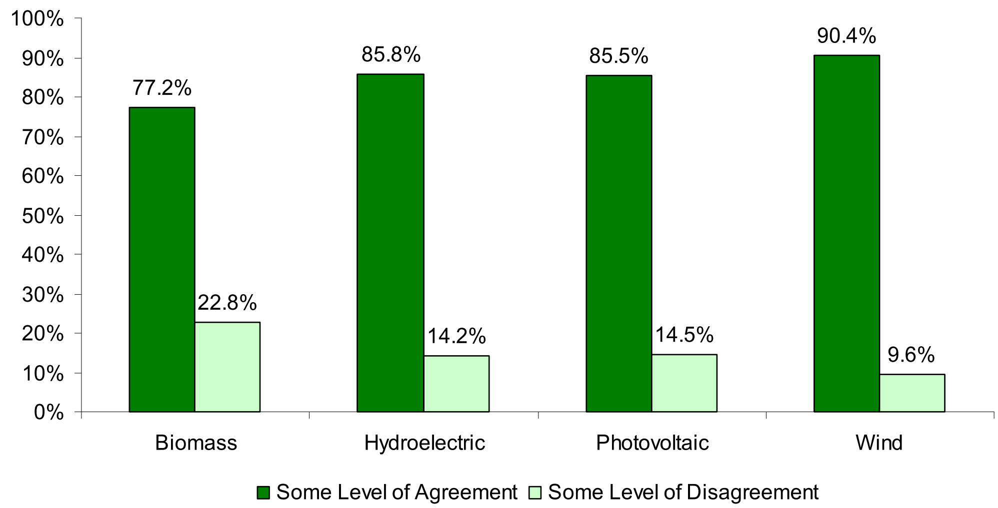




Customers in the top third of average energy consumption indicate a stronger level of agreement than do customers using lower levels of electricity.

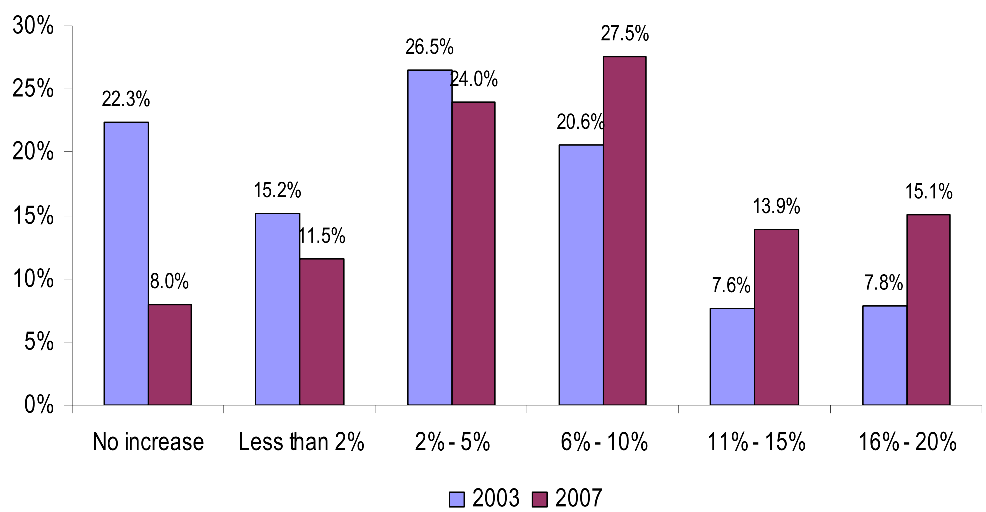
Question 3 - Holy Cross should participate in the development of the following renewable energy resources within its service territory: Biomass, Hydroelectric, Photovoltaic, Wind

The majority of all customers believe HCE should develop renewable resources as a source of generating electricity. 90.4% favor development of wind power resources, followed by hydroelectric at 85.8%, photovoltaic at 85.6%, and biomass at 77.2%.



Question 4 - Holy Cross should increase the percentage of renewable resources (biomass, hydroelectric, photovoltaic, and wind) in its power supply mix to the extent that my electricity costs increase by…

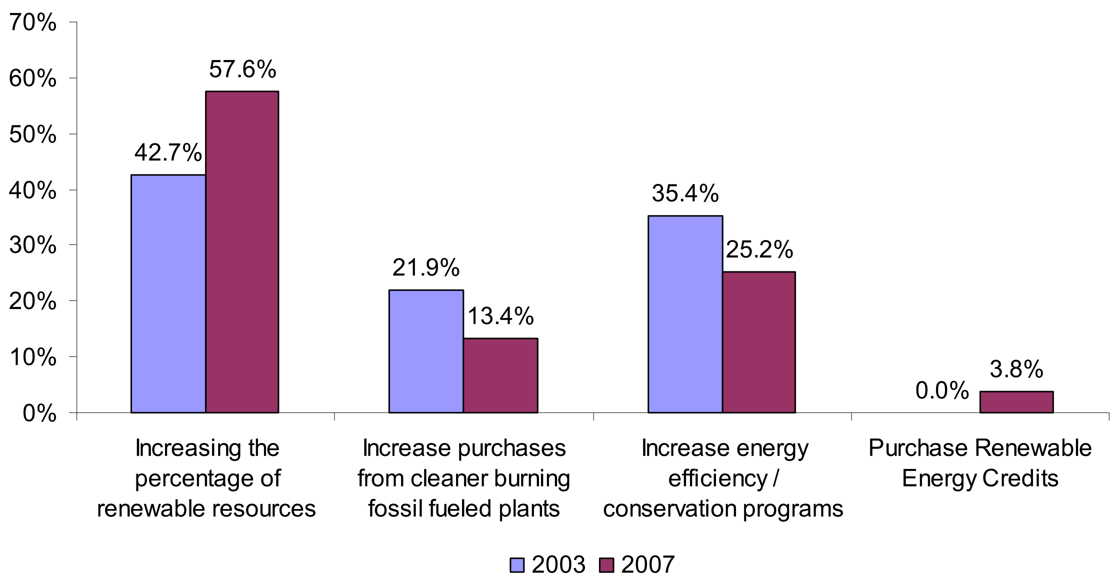
92% of all customers are willing to accept an increase in their electricity costs if HCE were to increase the percentage of renewable resources in its power supply mix. In 2003, only 78% were willing to pay more for their electricity given the same scenario. On average, customers are willing to pay approximately 7.7% more for electricity should HCE increase the percentage of renewable resources in its power supply mix. The average is up from 5.1% in the 2003 survey.



The higher energy use customers were willing to accept an 8.3% increase, while lower use customers were willing to accept a 7.1% increase. Customers in Pitkin County are willing to accept an 8.5% increase, while customers in Eagle County are willing to accept an increase of 7.5%, and customers in Garfield County would accept an increase of 6.3%.

Question 5 - If electric rates were increased to help fund certain programs, please rank the importance of the following: Increasing the percentage of renewable resources, Increase power supply purchases from cleaner burning fossil fueled plants, Increase energy efficiency and energy conservation programs, Purchase Renewable Energy Credits.

If electricity rates were increased to help fund a certain program, 57.6% of all customers favor increasing the percentage of renewable resources, 25.2% favor increasing energy efficiency and energy conservation programs, 13.4% favor increasing power supply purchases from cleaner burning fossil fueled plants, and 3.8% favor purchasing renewable energy credits. Consistent with other questions in the survey, customers favor increasing the percentage of renewable resources more today than they did in 2003.

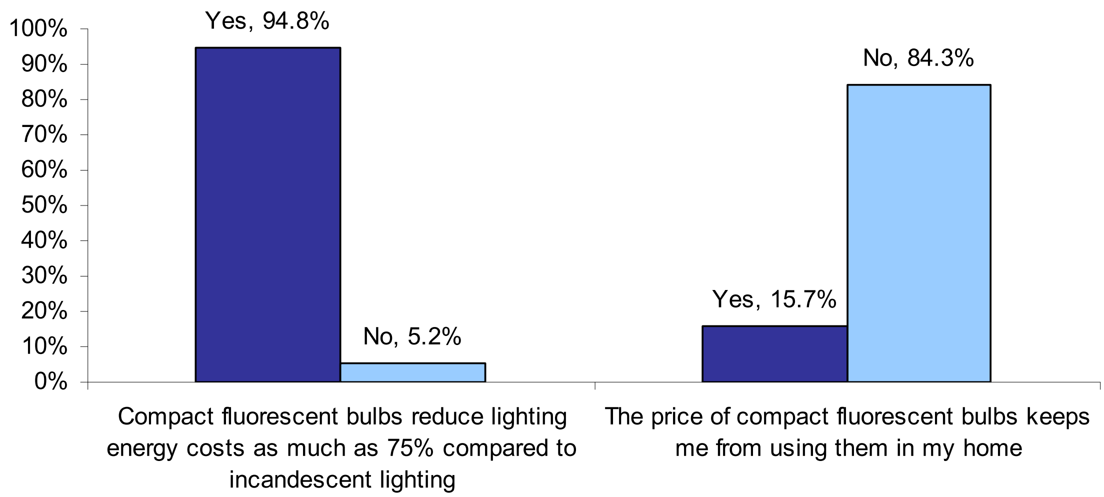


Note: Purchase Renewable Energy Credits (RECs) was not an option in the 2003 Survey

Customers in Pitkin County are stronger in their preference for increasing the percentage of renewable resources than are customers in Eagle and Garfield counties, while customers in Garfield County tend to favor energy efficiency and conservation programs more than customers in Pitkin and Eagle counties.

Question 6 through Question 8 - Compact fluorescent bulbs

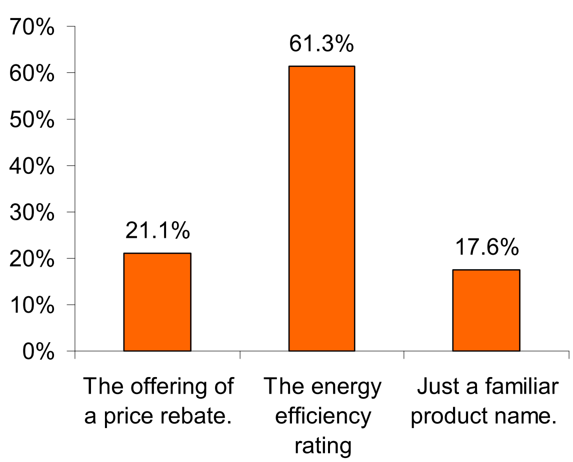
Overall, 75.5% of all customers agree that compact fluorescent bulbs provide quality lighting, and 25.5% agree very strongly with that they provide quality lighting. 94.8% believe compact fluorescent lighting reduces energy costs as much as 75 percent, and only 15.7% indicated that the price of fluorescent bulbs keeps them from using such lighting in their homes.



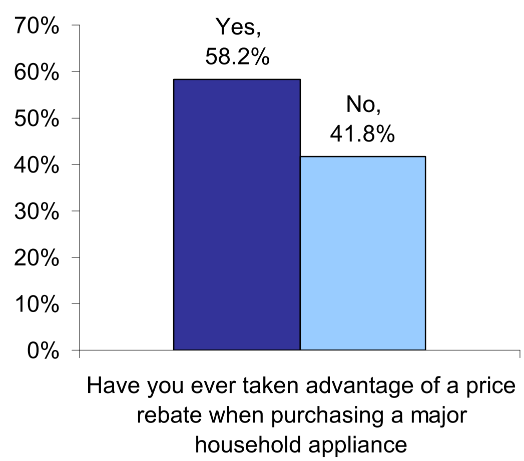
Question 9 and Question 10 – Major household appliances

When purchasing a new, major household appliance, 61.3% of all customers base their purchasing decision on the energy efficiency rating of the appliance, while only 21.1% base the decision on offering of a price rebate, and 17.6% base it on familiarity with the product name. 58.2% of all customers have taken advantage of a price rebate when purchasing a major household appliance.

Decision Criteria When Purchasing a Major Appliance

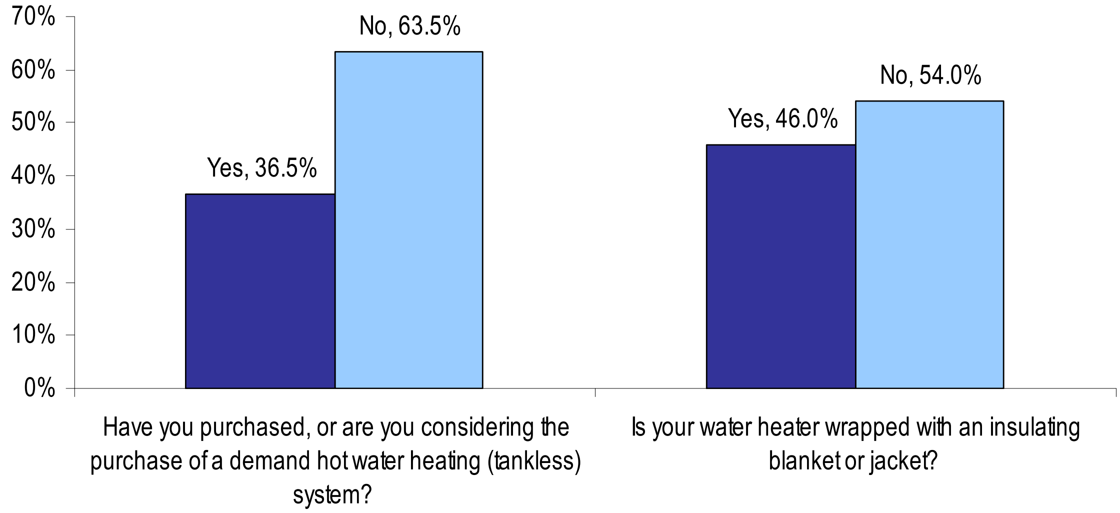


Taken Advantage of a Price Rebate



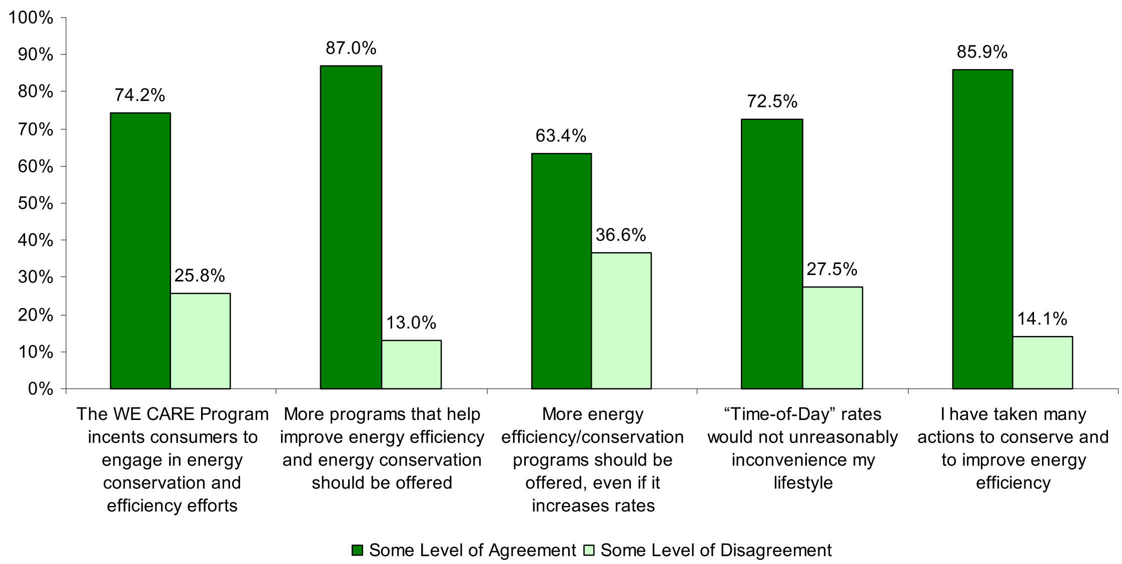
Question 11 and Question 12 – Water Heating

Only 36.5% of all customers have purchased, or are considering the purchase, of a tankless demand hot water heater. 46.0% of all customers have an insulating blanket or jacket on their water heater.



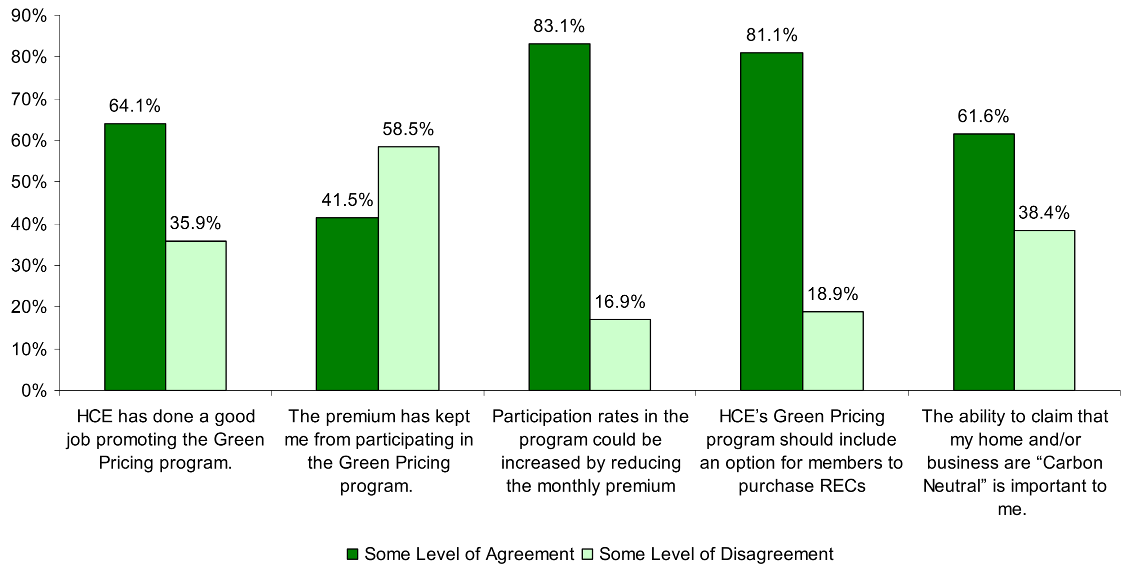
Question 13 through Question 17 – Energy Efficiency and Conservation Programs

Customers indicate they have taken significant actions towards conserving electricity and improving energy efficiency and believe HCE should provide additional programs to help consumers conserve energy.



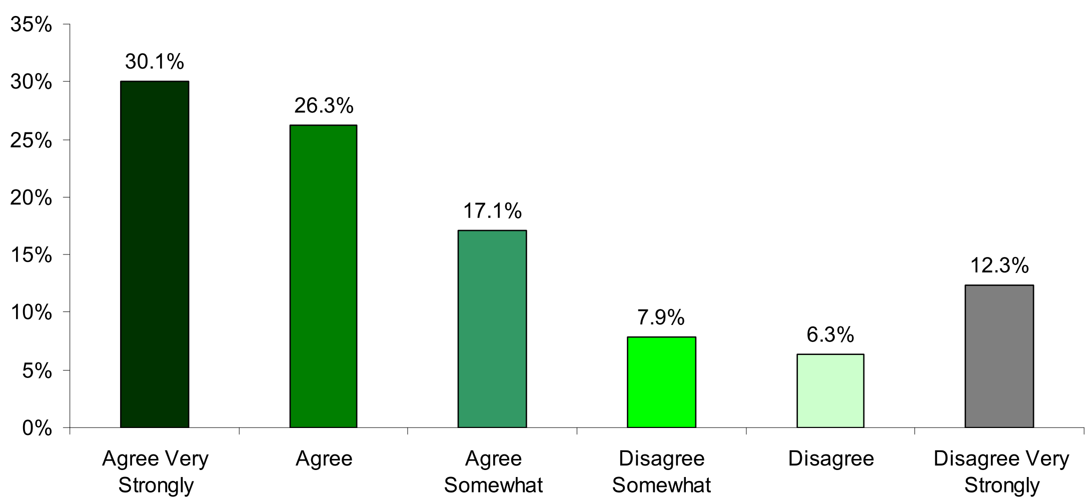
Question 18 through Question 22 – Green Pricing Program

Although customers indicate that the monthly premium charge has not kept them from participating in the Green Power program, they believe participation in the program would increase if the monthly premium was reduced. Customers believe the program should include an option to purchase Renewable Energy Credits.



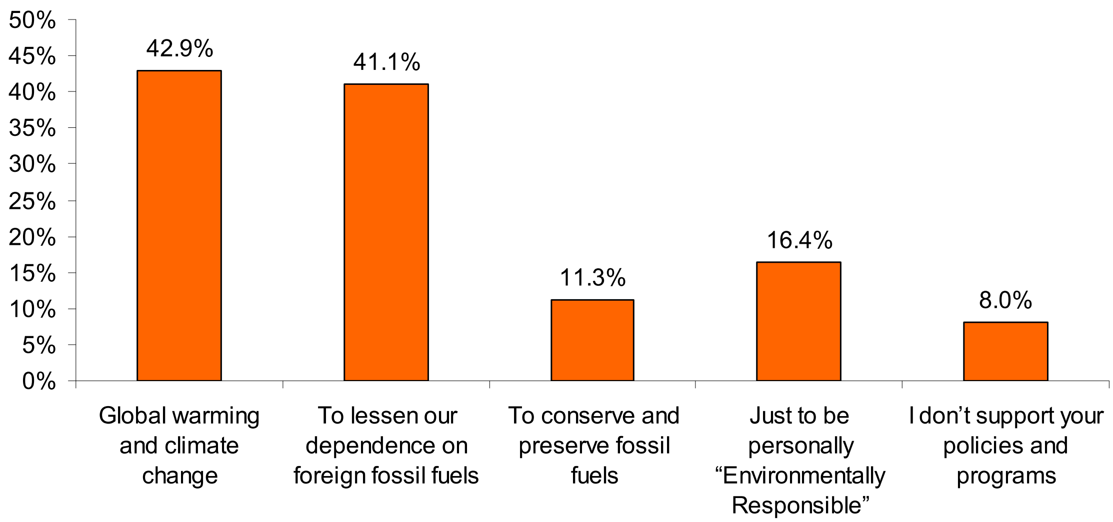
Question 23 – Renewable Energy Fund

73.5% of all customers support a monthly surcharge to their electric bill if such monies were specifically earmarked for the funding of large scale (> 50 kW) renewable energy generation projects (e.g. Run-of-the-river hydro, photovoltaic (PV) farm, or wind farm) within HCE's service territory.



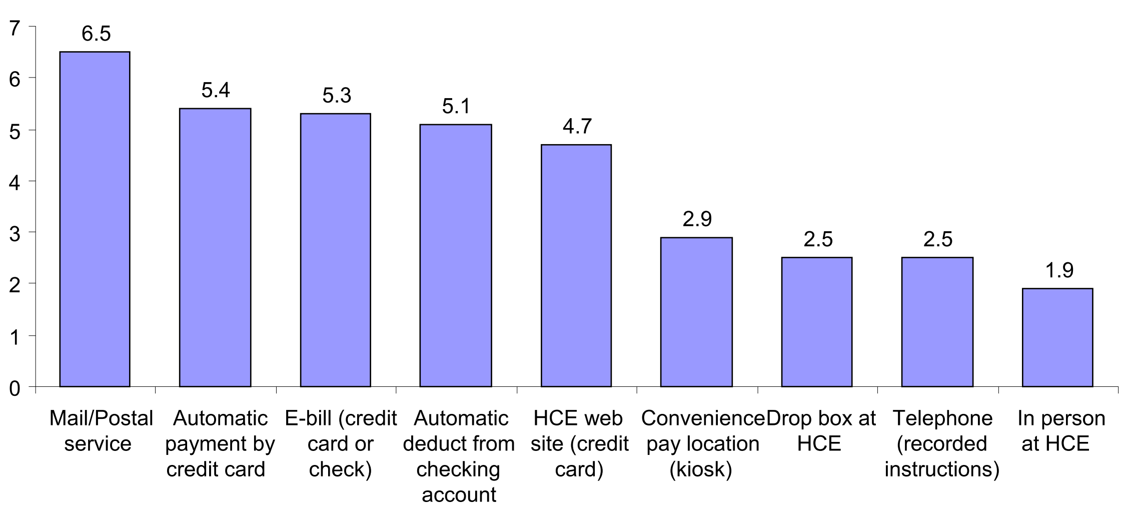
Question 24 – Factors Driving Support for Renewable Energy and Carbon Reduction Policies and Programs

The two primary factors driving support for renewable energy and carbon reduction programs and policies are global warming/climate change, at 42.9%, and lessening our dependence on foreign fossil fuels, at 41.1%. Only 16.4% indicated the reason as being environmentally responsible, 11.3% indicated to conserve and preserve fossil fuels for subsequent generations, and 8.0% stated they do no agree with HCE's policies and programs.



Question 25 – Preference for paying Your Holy Cross Energy Electric Bill

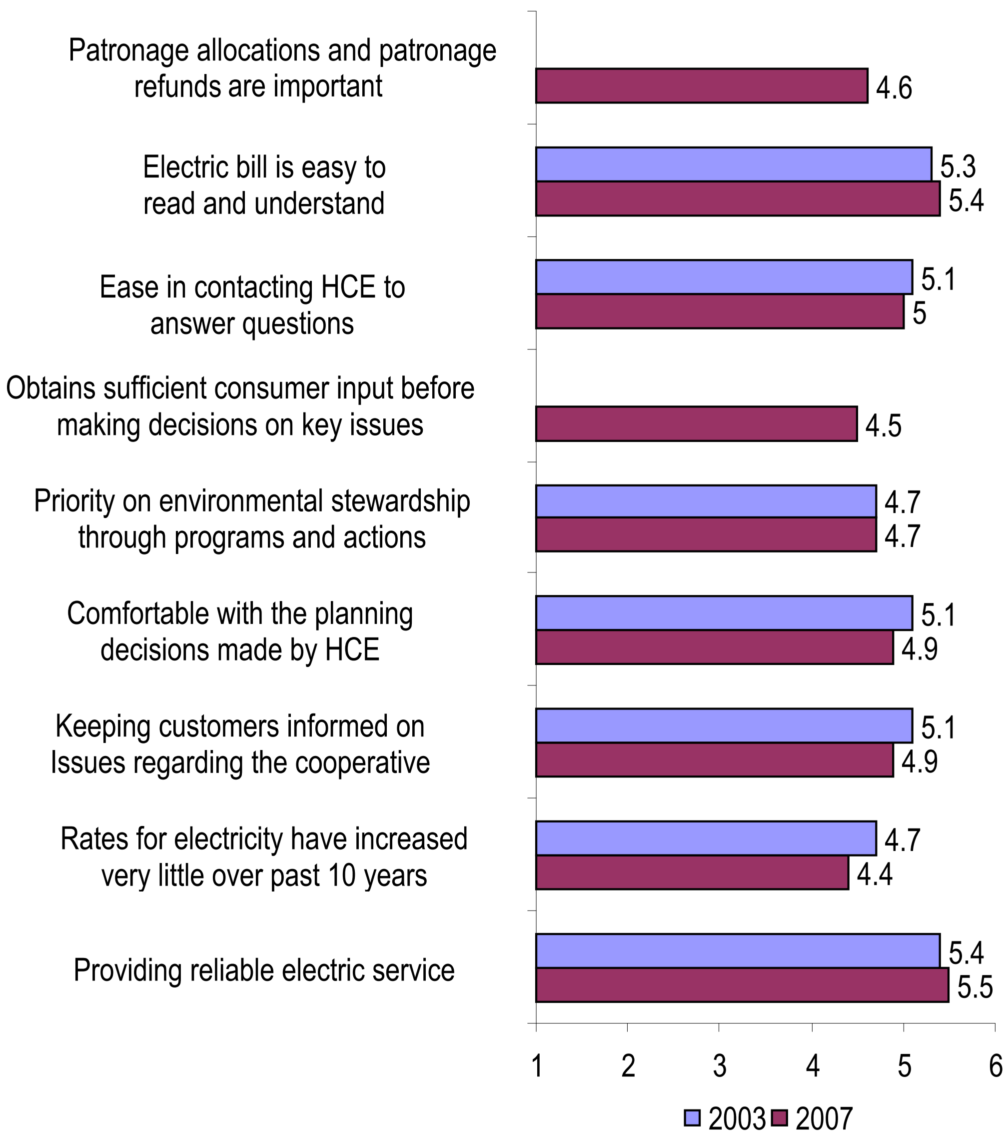
Mail/Postal service is still by far the preferred bill payment method. Web-based alternatives and automatic deductions from credit cards and checking accounts comprise the second level of preference. The following bar chart presents the results on a 1 to 10 scale, 10 being the highest preference.



Question 26 through Question 39 – Holy Cross Energy Report Card

A series of questions was included in the survey to address customer satisfaction regarding electric service reliability, electricity rates, communications between HCE and member consumers, and the overall management of HCE.

A comparison of report card issues between the 2003 and 2007 surveys is presented in the following chart. Statistics testing indicate there are no significant differences in customer opinions between the 2003 and 2007 surveys with respect to any of the following points.[2]



82.2% of all customers feel that as a member of Holy Cross Energy they own a portion of the entity.

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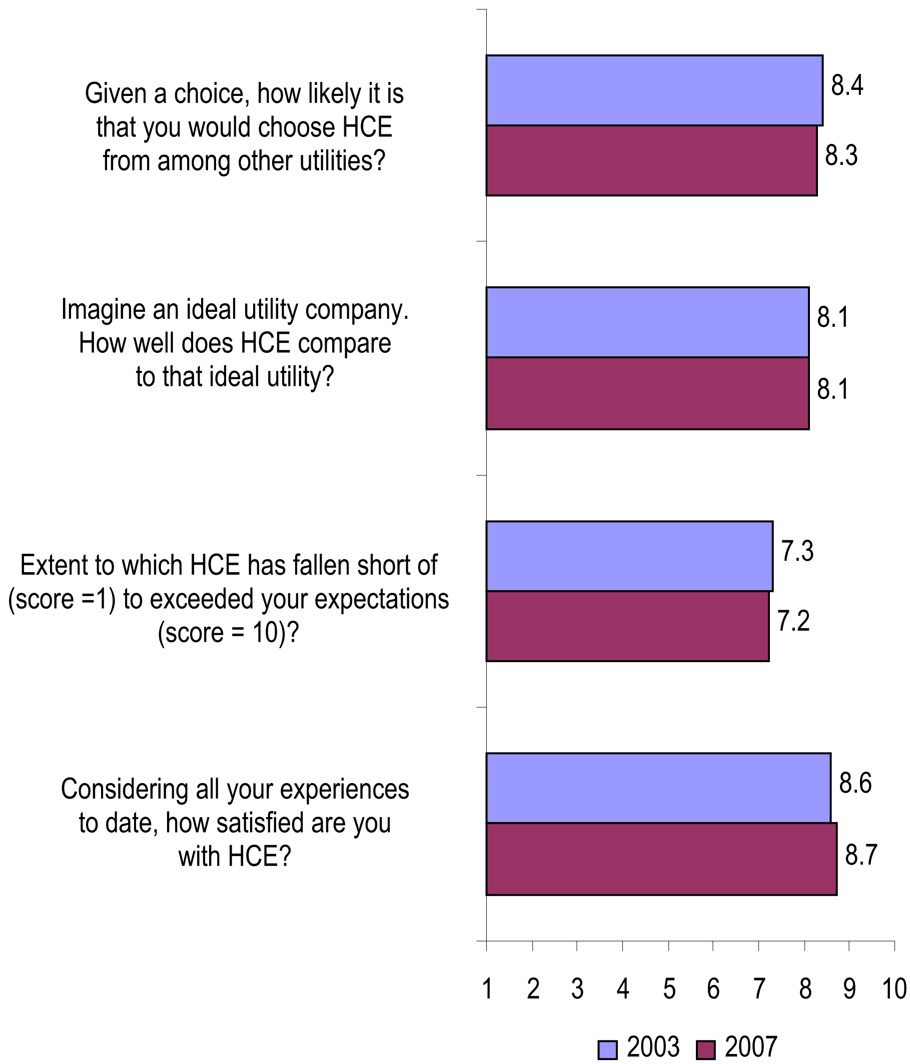
[2] Test for the difference between to sample proportions.

Four questions developed by NRECA were included in both the 2003 and 2007 surveys. Scoring is on a 1 to 10 basis, with 10 being most favorable. Again, there are no significant changes in customer opinions between the 2003 and 2007 surveys with respect to the following four points.



4 Questionnaire Design

The primary purpose of the survey was to determine customer attitudes and opinions regarding environmental stewardship, renewable energy development, HCE bill payment options, and satisfaction with HCE management and operations. The subject matter addressed in the survey required a basic understanding of environmental policies and programs; therefore, the first two pages of the questionnaire contained an overview and relevant facts and figures associated with the environmental issues that the survey addressed. The questionnaire also provided space for customers to provide comments on any specific issue they wished to bring to the attention of HCE management. The areas of focus were broken down into the following sections on the questionnaire:

Environmental Stewardship: Renewable Resources and Energy Conservation – addressed importance of the key aspects of HCE's power supply mix (environmental, reliability, cost), development of renewable resources, level of rate increase acceptable to increase the percentage of renewable resources in the power supply mix, awareness and knowledge of compact fluorescent bulbs, tankless water heaters, and price rebates on major household appliances, desire for more energy efficiency programs, the Green Pricing program, and attitudes regarding a Renewable Energy Fund.

Holy Cross Bill Payment Options – investigates customer preference for various traditional and new bill payment options.

Holy Cross Energy Report Card - addresses customer satisfaction with HCE service regarding reliability, rates, communications, and management.

Additional Comments - invites additional comments regarding issues important to the customer.

A copy of the questionnaire is presented in the Appendix.

5 Sample Design

The survey was conducted via the mail. Questionnaires were mailed to each person selected for the customer sample. The primary advantage of this approach over others (telephone or personal interview) is cost minimization. The most common disadvantage of mail-out surveys are lower response rates than personal interviews or telephone surveys.

The survey was designed to collect attitudes and opinions representative of all residential and commercial customers. HCE is unique in that approximately one quarter of all residential customers is seasonal and has permanent residences outside the Cooperative's service territory. The sample was designed to represent only residential and commercial customers residing or operating businesses in Eagle, Pitkin, and Garfield counties. The sample was designed to include all residential customers and commercial customers served on rate codes 1 through 52.

5.1 Population Frame

HCE's billing history for the twelve months ending March 2007 served as the population frame.[3] The population frame was narrowed to local residents and small commercial customers. Residential and small commercial customers take electric service on rate schedules 1 through 52. Local customers are defined as those residing or operating a business in Eagle, Garfield, Gunnison, Mesa, and Pitkin Counties and consuming electricity in the 12 consecutive months ending March 2007.

5.2 Sample Size

A sample size of 381 was required to satisfy the desired precision of 95% confidence with a ±5% margin of error. The equation used to estimate the required sample size is expressed as follows,

$$n_0 = \frac{(t^2) \times pq}{d^2} \qquad n = \frac{n_0}{1 + (n_0 - 1)/N}$$

n = sample size (including finite population correction)
n_0 = sample size (excluding finite population correction)
t = t value of the desired confidence interval
p = expected occurrence of the attributes
q = $(1 - p)$
d = desired level of precision (±) for the confidence interval
N = population

where the value of p was set to 50%, which produces the highest sample size possible given the desired confidence and level of precision parameters:

$$384 = \frac{(1.962) \times (.5)(1-.5)}{(.05)} \qquad 381 = \frac{384}{1.0077}$$

[3] The population frame is the source from which sample customers are selected.

5.3 Sample Selection

A response rate of 17 percent was achieved in the 2003 Consumer Survey conducted by Holy Cross Energy. Assuming a similar response rate for the 2007 survey, a sample of 2,709 customers was selected in efforts to receive at least 381 valid responses. A systematic sampling methodology was employed. All accounts were sorted in ascending order on location and average kWh usage (twelve month period). Once sorted, every i^{th} account was selected beginning with a randomly selected seed value. The value of i was dependent upon the total number of qualified accounts in the population. In calculating i, the total qualified population was divided by the desired sample size. The quotient was rounded down to the nearest whole number to insure the sample included the required number of accounts.

5.4 Sample Validation

2,709 questionnaires were mailed to sample customers, of which 36 were returned as undeliverable. 349 valid responses were collected from the survey, resulting in a response rate of just over 13 percent. Representation of the sample in terms of geographic location, average kWh consumption was excellent; therefore, results were not weighted to account for differences between population and sample distributions. Tables 5.1 through 5.3 present a comparison of population and sample distributions.

Table 5.1
Response by County

County	Population	Sample	Difference
Pitkin	24.0%	25%	1%
Eagle	63.0%	59%	-4%
Garfield	13.0%	16%	3%
	100%	100%	

Table 5.2
Response by Average kWh Consumption

	Population	Sample	Difference
Average Monthly kWh per Customer	1,208	1,254	3.8%

Table 5.3
Response by Zip Code

Zip Code	Population	Sample	Difference
81601	3.4%	1.5%	-1.9%
81602	0.8%	0.3%	-0.5%
81611	9.2%	10.7%	1.6%
81612	7.3%	7.4%	0.1%
81615	4.8%	4.3%	-0.5%
81620	13.0%	12.0%	-1.0%
81621	9.1%	12.0%	2.9%
81623	13.8%	6.7%	-7.1%
81631	6.9%	9.5%	2.6%
81632	7.2%	7.4%	0.2%
81635	7.4%	5.8%	-1.6%
81636	0.2%	0.0%	-0.2%
81637	2.3%	2.5%	0.1%
81642	0.1%	0.0%	-0.1%
81645	0.1%	0.3%	0.2%
81647	0.6%	0.0%	-0.6%
81650	0.9%	1.2%	0.4%
81652	1.3%	0.3%	-1.0%
81654	1.8%	2.8%	1.0%
81655	0.1%	0.3%	0.2%
81656	0.1%	0.0%	-0.1%
81657	6.6%	9.8%	3.2%
81658	3.0%	5.2%	2.2%

5.5 Survey Administration

Survey packets were mailed to each sample customer. Each packet contained a questionnaire and a postage-paid return envelope. Approximately ten days after the questionnaires were mailed, post card reminders were mailed to all sample customers. The purpose of the reminder cards was to improve the response rate. The completed questionnaires were reviewed to exclude invalid responses and then entered into electronic files for processing.

5.6 Level of Precision

The desired level of precision was ±5 percent at the 95 percent confidence level. Based on 349 valid responses, the level precision achieved was ±5.6 percent at the 95 percent confidence level. In laymen’s terms, level of precision relates to accuracy. For example, if the point estimate for a particular question is 52 percent, it is inferred that the true population value falls within the range of 47 to 57 percent (52.0 percent ±5.0 percent).